environmental conservation

The Oil and Gas Industries: An Overview

National Petroleum Council/1981

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Alton W. Whitehouse, Jr., Chairman,
Committee on Environmental Conservation

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.

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Table of Contents

Page

Introduction 1

Executive Summary

Findings and Conclusions 3
Summary of Costs—Past and Future 7

Chapter One: General Considerations Regarding Environmental Conservation

Introduction 9
U.S. Energy and Petroleum Supply/Demand Projections 9
Legislative and Regulatory Considerations 17
Costs of Environmental Controls to the Petroleum Industry 27
References and Notes 42

Chapter Two: Petroleum Industry Operations and the Environment

Introduction 43
Exploration and Production 43
Refining 54
Storage, Transportation, and Marketing 59
Product Use 61
Fate and Effects of Spills 64
Energy Facility Siting 69
References 72

Chapter Three: Other Issues of the 1980's

Acid Rain 73
CO_2 "Greenhouse" Effect 76
Indoor Air Pollution 78
National Ambient Air Quality Standards 78
References 80

Appendices

Appendix A: Request Letter, Description of the NPC, and NPC Membership Roster A-1
Appendix B: Committee and Task Group Rosters B-1
Appendix C: Environmental and Resource Conservation Laws Enacted by Congress, 1970-1980 .... C-1
Appendix D: Summary of Comments on *Synthetic Fuels and the Environment* D-1
Appendix E: Executive Summary, *U.S. Arctic Oil and Gas* (prepared by the NPC Committee on Arctic Oil and Gas Resources) E-1
Appendix F: Acronyms and Abbreviations F-1

Introduction

At the request of the Secretary of Energy, the National Petroleum Council (NPC) undertook this comprehensive study, which updates the Council's 1971 report, *Environmental Conservation—The Oil and Gas Industries*. In his request, the Secretary stated that "special emphasis should be placed on determining the environmental problems that are most serious and the impact of current environmental control regulations on the availability and cost of petroleum products and natural gas." (See Appendix A for the Secretary's request letter and a description of the NPC.)

To respond to the Secretary's request, the Council established the NPC Committee on Environmental Conservation under the chairmanship of Alton W. Whitehouse, Jr., Chairman of the Board and Chief Executive Officer, The Standard Oil Company (Ohio). Hon. William A. Vaughan, Assistant Secretary for Environmental Protection, Safety, and Emergency Preparedness, U.S. Department of Energy, was designated Government Cochairman of the Committee. The Committee was assisted by a Coordinating Subcommittee and five task groups: air quality, water quality, land use, hazardous wastes, and synthetic fuels. (See Appendix B for the organization chart and Committee and subgroup rosters).

The study is presented in two parts. This volume represents an overview of the environmental considerations of oil and gas operations and petroleum product use. These considerations are discussed in more detail in a report expected to be published by the Council in mid-1982.

The Secretary concurrently requested the Council to undertake a study of the major issues relating to the development of U.S. Arctic oil and gas resources. The environmental assessment for the Arctic study was critical to both study efforts and was coordinated between both studies. The Executive Summary of the NPC's 1981 report, *U.S. Arctic Oil and Gas*, is contained in this report as Appendix E. The complete report is available from the National Petroleum Council.

It is appropriate that the Council update the petroleum industry's environmental considerations and concerns at this time. The climate under which the petroleum industry operates today has changed dramatically in the 10 years since the NPC last reported on environmental conservation:

- The energy supply/demand balance has shifted significantly, and there is a newly recognized need for energy security. Achieving energy security requires that environmental concerns be balanced against the need to develop domestic energy supplies.
- For the rest of this century increasing emphasis will be placed on the development of non-oil and non-gas resources, such as coal, nuclear, and synthetic fuels. As a result, environmental considerations should recognize the changing mix of energy supply.
- The petroleum industry has made substantial progress in environmental conservation in the past decade, and the major environmental concerns perceived in the 1970's as arising from the industry are now vastly diminished because pollution sources are under effective control.
- Many of the environmental control strategies in place today are based in large part on environmental legislation and regulation written during the 1960's and 1970's. A re-examination of these control strategies is appropriate, as some may place unnecessary constraints on domestic energy development.

The objectives of this report are twofold: First, to describe current industry operations and explain the facilities and procedures that are used to protect the environment; and second, to focus attention on the specific areas of environmental law and regulation that have directly affected the availability and cost of petroleum products and natural gas.

It is the Council's desire to respond positively to the Secretary's request. While a number of sections may appear to criticize or condemn the key environmentally oriented laws that have been enacted during the decade of the 1970's, many of the laws and regulations discussed in the report are in large part clearly useful and worthwhile. The Council's comments in this regard are intended to be constructive and to express the Council's concern for the high degree of complexity and uncertainty, and the potential for long delays that impede the achievement of balance between the national goals of energy development and environmental protection.

Executive Summary

Findings and Conclusions

The Council, in responding to the Secretary's request, sought to identify those environmental issues that will be the focus of continued debate and research in the decade of the 1980's. The Council also examined the impacts of the petroleum industry on the environment, and the impact of environmental legislative, regulatory, and administrative actions that adversely affect the cost or availability of petroleum products, natural gas, and synthetic fuels. The findings and conclusions reached through this analysis are summarized below. These issues and impacts are discussed in more detail in the following chapters.

Significant Environmental Issues of the 1980's

The following significant environmental issues must be resolved promptly as the nation seeks in the 1980's to balance the goals of energy supply and security with the goals of environmental quality.

- Access to federal lands for the purpose of resource assessment and possible future development
- Delay and uncertainty caused by the complexity of regulatory requirements, including permitting procedures, the number of government authorities involved, and the opportunities for legal intervention by third parties
- Siting of energy facilities, especially production and transportation facilities, that are determined by the location of natural resources
- Incorporation of scientifically acceptable techniques in setting standards, such as National Ambient Air Quality Standards (NAAQS) and water quality standards
- Siting and operation of facilities for hazardous waste management
- The ecological and public health effects of, and the control strategies for, the synfuels industry.

There are also a number of issues whose causes are not clearly defined and which are affected by many factors and industries, of which the petroleum industry is only one. These issues are: the ecological and public health effects of, and the control strategies for, acid rain; the CO_2 "greenhouse" effect; groundwater contamination; and indoor air pollution.

To achieve a satisfactory resolution of these issues will require not only the full cooperation of government, industry, and private citizen groups, but also a commitment to research activities, especially by government and industry segments, that will quantify the impacts, clarify the issues, and determine appropriate solutions to the problems identified.

Industry Impacts on the Environment

As part of its effort to "determine the environmental problems that are most serious" as requested by the Secretary of Energy, the Council examined impacts of the petroleum industry on the environment. These impacts are a function of the industry's operations (exploration and production; refining; and storage, transportation, and marketing) as well as the use of its products. The Council's findings with respect to the industry's conventional operations and the projected

synfuels industry's operations are summarized below; those resulting from product use are discussed in Chapter Two.

Conventional Oil and Gas Operations

1. Impacts on the environment from current and projected routine conventional petroleum industry operations are largely known and controlled. During the past decade the industry has made significant progress in reducing its impacts on the environment; however, certain long-term possible impacts on the environment are still being investigated.
   - Petroleum industry operations emissions represent only a small fraction of national air emissions. For example, petroleum refining emissions represent only 0.9 percent of the nation's carbon monoxide (CO) emissions, 0.5 percent of total suspended particulates (TSP), 2.8 percent of sulfur dioxide (SO_2), 1.5 percent of nitrogen oxide (NO_x) and 3.9 percent of volatile organic compounds (VOC). In addition, within the refining sector, significant reductions in air emissions per barrel of crude oil run were achieved during the last decade; e.g., a decrease of 68.6 percent in CO, 47.2 percent in TSP, 19.4 percent in SO_2, 19.3 percent in NO_x, and 2.0 percent in VOC.
   - Prevention of Significant Deterioration (PSD) requirements, nonattainment area restrictions, New Source Performance Standards (NSPS), and provisions for detailed pre-construction review of all major stationary sources of air emissions provide the regulatory framework for controlling air emissions.
   - The refining industry has achieved a greater than 91 percent reduction in the discharge of conventional water pollutants from 1967 to 1979. Additional data indicate that nonconventional pollutants are well controlled and that the existing Best Practicable Control Technology (BPT) treatment systems remove toxic pollutants to levels barely detectable by the modern analytical techniques, where they are found at all.
   - The National Pollutant Discharge Elimination System (NPDES) Permit Program provides regulatory authority for controlling discharges to receiving waters.
   - Current industry practices demonstrate that significant improvements in the treatment and disposal of industry-generated wastes have occurred.
   - The Resource Conservation and Recovery Act of 1976 (RCRA) provides for regulation of the disposal of hazardous wastes.
   - Effects of trace toxic materials in air and water are still being evaluated.
   - Past operations and practices that had caused or contributed to adverse environmental impacts have been largely replaced by improved technology and engineering.
   - Permitted operational discharges occasionally create minor localized effects, but such discharges cause only negligible overall environmental impacts.
   - Some long-term possible problems, such as acid rain and the CO_2 "greenhouse" effect, are not yet understood well enough to determine impacts or to establish final control strategies.

2. Accidental releases of oil and hazardous substances from conventional and routine petroleum industry operations usually do not constitute an irreversible or serious long-term environmental hazard.
   - Major oil spills are more likely to occur in the open ocean. The dilution potential of the open sea and the dispersion, weathering, and loss of toxic constituents, primarily to the atmosphere, make it improbable that oils spilled in deep-sea areas could reach bottom-dwelling (benthic) marine life, much less in toxic amounts. Most oil spills, even those impacting coastal areas, have not had serious long-term effects. Recovery has been rapid in most situations, particularly in relation to marine productivity and populations.
   - Studies following the 1970 Chevron Main Pass Block 41 spill in the Gulf of Mexico, the 1977 Ekofisk oil spill in the deeper waters of the North Sea, and even the very large oil discharge from the Ixtoc blowout in the Bay of Campeche in 1979, indicate that these spills appear to have few or no significant adverse effects in offshore waters.
   - Oil spills create a variety of severe short-term impacts, which can affect commerce, areas of habitation, recreation, and shorelines, particularly when spills occur in near-shore waters. Near-shore spills and their resulting "chocolate mousse" emulsions can create unsightly messes on beaches and shorelines, cause conspicuous casualties among sea birds, and kill benthic organisms. Especially

sensitive to short-term effects are near-shore ecosystems such as coral islands, salt marshes, and mangrove communities.

- Hazardous substance spills do occur occasionally and in some cases cause serious, but temporary, localized effects. Very few materials on the Environmental Protection Agency (EPA) hazardous substance list are used in the petroleum industry. These materials are handled with care, and spills in excess of the appropriate reportable quantity are rare. When operational spills do occur they are typically contained within tank dikes or removed during wastewater treating operations so that actual harmful releases to navigable waters are minimal.
- Gasoline leaks from service station underground tanks and piping occur throughout the industry and have the potential for serious harm to people, property, and the environment.

3. Groundwater contamination can create serious local problems, and further definition of the extent and degree of risk is required.
   - The petroleum industry is only one of many industries that are concerned with this problem. Nationwide, the extent and risk presented by groundwater contamination from all sources is still being investigated. The prevention and control of groundwater contamination are regulated under the Safe Drinking Water Act and RCRA, as well as many individual state programs.
   - Within the petroleum industry, controls are in place to protect groundwater from the reinjection of produced waters from exploration and production operations, underground cavern storage of petroleum products, and for the detection and cleanup of spills and leaks from petroleum facilities, especially pipelines and service stations.

Synfuels Operations

The projected synthetic fuels industry operations, when assessed on a site- and process-specific basis, are not expected to pose a major threat to the environment. This does not imply that the potential for some long-term chronic effects or regional scale problems has been eliminated. As the industry enters the commercial development stage, more operational data, together with the existing research and development and pilot stage information, will be available for environmental evaluation and any necessary additional control strategies. In addition, many aspects of the developing synfuels industry are common to conventional technologies, e.g., mining and refining. Environmental effects of synfuels development will continue to be evaluated, and areas of concern that will receive special attention are:

1. Water Quality and Water Availability
   - Evaluation of the impact of mining activities on aquifers
   - Impact of waste disposal areas on groundwater
   - Long-term effects of leachate from in situ and modified in situ shale oil production
   - Water resource development and availability.
2. Air Quality
   - Effect of fugitive dust.
3. Solid Wastes
   - Management and disposal of large quantities of solid wastes.
4. Land Use
   - Closure, revegetation, and/or reclamation of affected land areas.
5. Health and Product Safety
   - The toxicological and ecological properties of synthetic fuels, intermediates and by-products, and wastes.
6. Other
   - Socio-economic impacts of synthetic fuel resource development
   - Identification of special problems from accidental releases of synthetic fuels products.

Environmental Legislative, Regulatory, and Administrative Actions That Adversely Affect the Cost or Availability of Petroleum Products, Natural Gas, and Synfuels

The Council also examined the impact of environmental legislative, regulatory, and administrative actions that adversely affect the cost or availability of petroleum products, natural gas, and synfuels. The Council's findings are summarized below.

1. Land Use
   - Past failures to adequately lease offshore government lands have delayed resource

assessment, exploratory drilling, and production. Withdrawals and extended classification determinations of onshore government lands have also inhibited resource assessment and potential development of such areas.

- Coastal Zone Management (CZM) consistency review results in delays of leasing and exploration activities.
- The designation of Marine Sanctuaries can prevent oil and gas activity in or near designated sanctuaries.
- The Endangered Species Act can prevent or delay development of energy and water resources.

2. Air Quality

- PSD increments limit allowable new growth, especially in or near Class I areas.
- Construction of modified refining and new transportation and production facilities in nonattainment areas may be banned if the State Implementation Plans (SIPs) are not approved.
- There is an insufficient pool of offsets in some nonattainment areas to meet permit requirements for new or modified sources of emissions.
- The application of Class I visibility protection criteria to adjacent areas, as embodied in the integral vista concept, can restrict resource development.
- Outer Continental Shelf (OCS) air regulations pertaining to attainment, and PSD increments could inhibit OCS oil and gas development.
- Lack of guidance in determination of Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER), and the frequent disagreement between and among federal, state, and local agencies and the industry over the level of controls contribute to delays in processing and issuing permits.
- Monitoring and data gathering regulatory requirements are frequently excessive, costly, and time-consuming; in combination, these requirements can result in lengthy delays of new and expanded energy sources.
- Modeling requirements are expensive and time-consuming, and, more importantly, the air quality predictions are usually conservative. They can lead to delays and costly restrictions on new and modified sources that may be unnecessary to protect air quality or achieve environmental benefits.
- Automotive exhaust emission restrictions, particularly those that prevent the use of alkyl lead compounds in automotive fuels, reduce the amount of transportation fuel that can be obtained from a given quantity of crude oil.
- Restrictions imposed by many local jurisdictions on the sulfur content of petroleum fuels have changed supply patterns for heavier fuels in particular and have increased the price for suitable fuels in low-sulfur fuel regions.
- Guidance documents prepared by EPA, such as the Control Techniques Guidelines, have been interpreted all too often to be standards or regulations by the states or EPA regions. This has frequently led to more stringent regulations and/or permit limits on industry, with resulting higher costs, than were necessary to satisfy air quality requirements.

3. Water Quality

- Unreasonable delays in issuance of NPDES permits for oil and gas exploratory drilling operations in almost every offshore area of the United States have raised compliance costs and delayed efforts to find oil and gas. The EPA's recently initiated policy on issuing general NPDES permits could alleviate the delay problem.
- Present wetlands policy has delayed issuance of dredge and fill permits by the U.S. Army Corps of Engineers.
- The EPA policy of effectively requiring state agencies to adopt the EPA water quality criteria as state standards frequently could place unrealistic limits on wastewater discharges from both new and existing facilities. The EPA water quality criteria on some toxic pollutants are based on very limited data and some criteria are below the detection limits of current analytical techniques.
- Failure of EPA to issue petroleum refining effluent guidelines within the deadlines set by court order and statute has introduced uncertainty into the regulatory process. This uncertainty exacerbates the problems faced by refiners who need sufficient lead time to design and install wastewater treatment equipment to comply with the July 1, 1984, deadline, especially if additional equipment is necessary. In addition, EPA's proposed guidelines are overly severe and fail to consider industry progress and performance in water pollution control.

4. Hazardous Wastes
   - Regulation of hazardous waste and waste management facilities has not been based on the degree of hazard presented to human health and the environment by the specific wastes being stored. As a result, unduly restrictive and costly measures may be required.
   - Complex technical and societal problems of siting new hazardous waste management facilities will hamper the nation's ability to adequately dispose of its waste. If local sites are unavailable, transportation of hazardous wastes to remote sites will be costly and may present a greater risk to the environment.

Summary of Costs—Past and Future

Costs of environmental regulations to the petroleum industry have been in the past and will be in the future a significant component of industry expenditures. Expenditures to protect environmental quality and human health are recognized to be a necessary cost of doing business. It is also important to recognize, however, that environmental standards more stringent than those necessary to protect the environment and human health impose higher industry capital and operating costs and, ultimately, higher product costs to the consumer. Cost is, of course, just one of the factors in the achievement of a balance between environmental protection and energy development and security.

In part, these higher costs result from overly conservative and protective control strategies, some of which are not based on valid scientific studies that have been subject to peer review. The Council believes that a better balance is needed, and that control strategies should be developed based on valid scientific studies that have been subject to peer review.

In addition to these higher identified costs are the significant, but difficult to quantify, "costs of delay" that result from delays in the permitting process. The Council believes that steps are needed to improve the permitting process in order to facilitate domestic oil and gas resource development.

A recent petroleum industry expenditure survey (representing 70 percent of refining capacity) by the American Petroleum Institute (API) indicates that expenditures for environmental protection during the 1971-1980 period totaled $21.1 billion as spent. A 1980 Battelle study forecasts the capital expenditures of the conventional petroleum industry for environmental protection (excluding the impact of RCRA) to be $57 billion (constant 1979 dollars), for the 1970-1990 period, with annual operating costs of about $6 billion (constant 1979 dollars) per year in the latter half of the 1980's. For additional details and a breakdown of the expenditures, see Tables 6 through 14 in Chapter One.

In order to put these expenditures and forecasted costs in perspective, Table 15 of Chapter One shows the estimated incremental environmental control expenditures for both the public and private sectors in the United States for the 1979-1988 period, as projected by the Council on Environmental Quality in 1980. During the 10 years from 1979 through 1988, total spending in response to the federal environmental quality regulations is expected to reach $518.5 billion.

The estimated breakdown of this spending by environmental program is presented below:

- Air—$300 billion (58 percent)
- Water—$170 billion (33 percent)
- Land Reclamation—$15.3 billion (3 percent)
- Hazardous Waste Management—$15.4 billion (3 percent)
- Control of Hazardous Substances—$8.2 billion (2 percent)
- Noise Control—$6.9 billion (1 percent).

These levels of environmental expenditures by the petroleum industry as well as other public and private segments within the United States evidence a continuing commitment to environmental quality.

Chapter One
General Considerations Regarding Environmental Conservation

Introduction

Before examining the issues concerning the petroleum industry and the environment, it is helpful to place into perspective the future direction of the industry. The volume and components of energy production and consumption have a direct bearing on the nature and extent of the environmental protection mechanisms necessary.

Some of the basic environmental laws were passed in the 1960's and early 1970's, when the price of crude oil was extremely low and the domestic economy and energy consumption were believed to be continuing to expand unchecked. In addition, state and local governments were experiencing difficulties in meeting their constituents' needs resulting from that growth. A national concern developed that state and local government entities could not properly manage the complex responsibilities of environmental protection, that federal protection and standards were required, and legislation to that effect was enacted.

The energy demand growth expectation was linked directly to the expected Gross National Product (GNP) growth, with some early 1970's estimates projecting that 1985 U.S. energy consumption would be as high as 130 quadrillion Btu's. (Current estimates are on the order of 83 quadrillion Btu's or less.) High energy consumption projections imply higher levels of emissions.

The early 1970's energy projections were proven wrong by events of that decade. Figure 1 compares the actual energy consumption during the 1970-1980 period with energy demand forecasts prepared by the NPC at the beginning, mid-point, and end of the decade. The Organization of Petroleum Exporting Countries crude oil price increases and the embargo of 1973-1974 by the Arab member countries, together with the cutoff of Iranian imports into the United States in December 1978 and other economic and political events, dramatically altered the energy consumption patterns in the United States and changed the public perception of energy and its position in the economy.

To place the petroleum industry's future contributions to U.S. energy supply in perspective, a brief summary of a recent supply/demand projection through 1990 is presented. Following that section is a history and description of the major environmental laws concerning the oil and gas industry and a discussion of the costs of environmental control to the petroleum industry.

U.S. Energy and Petroleum Supply/Demand Projections

The following projections were drawn from the Low Demand Case of the NPC's 1980 report, *Refinery Flexibility*. These projections present the "adjusted average" balances of the lowest quartile responses to a 1980 NPC survey of 35 organizations that regularly prepare such forecasts. The NPC believes that these projections present a representative assessment of the trend of future energy supply/demand in this country, although many observers of the energy situation are projecting even lower levels of U.S. energy demand in 1990.

U.S. Total Energy Consumption

During the decade of the 1980's, U.S. energy consumption is expected to experience

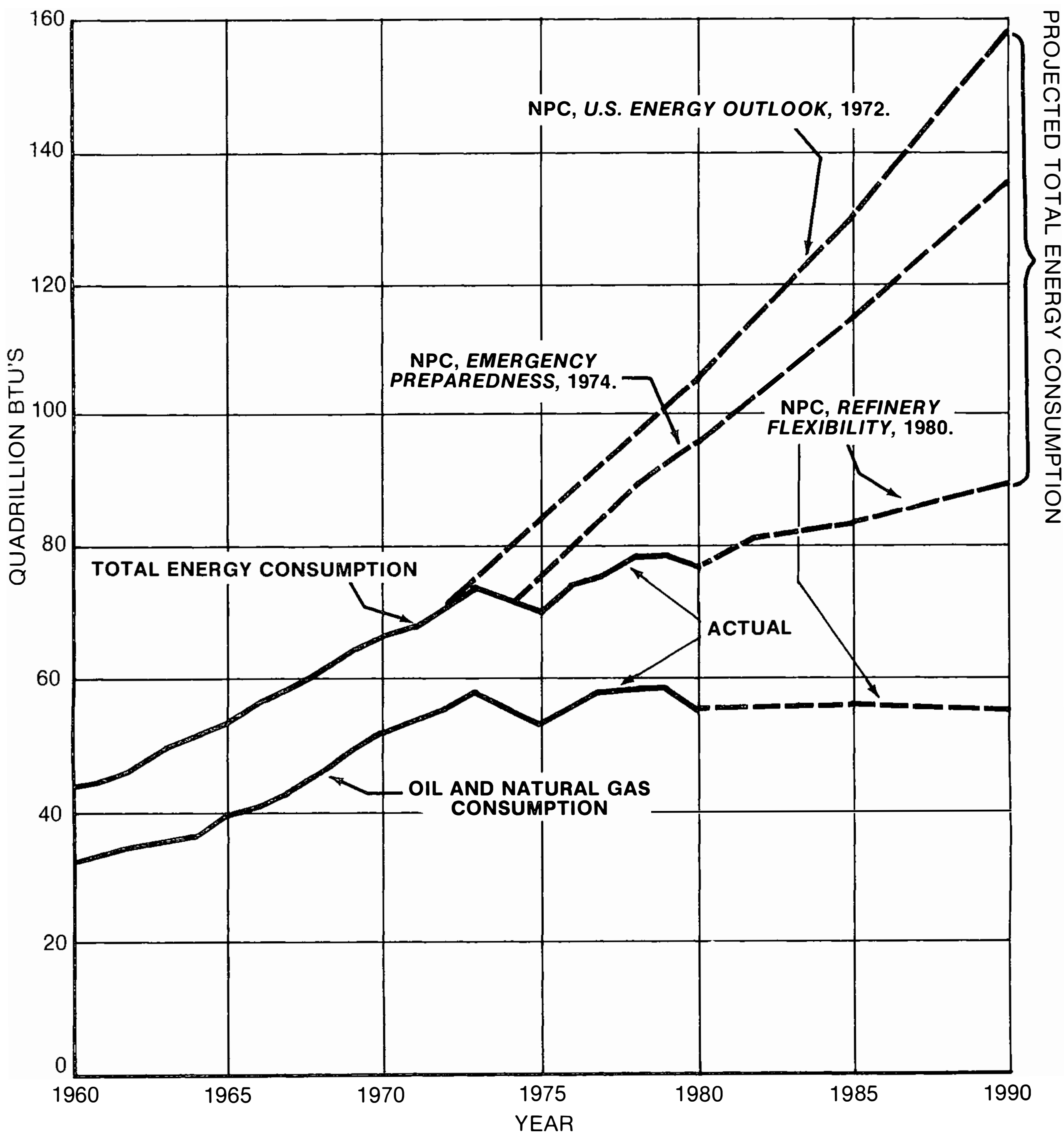


Figure 1. Comparison of Actual Energy Consumption with Projections.

NOTE: Actual data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Projected data from National Petroleum Council, as cited.

a 1.5 percent annual rate of growth, while comparable real GNP growth is expected to be 2.1 percent per year. During the 1960's and 1970's the annual average increase in consumption was 4.2 percent and 1.3 percent, respectively, with annual average GNP growth of 3.8 percent and 3.3 percent. Total U.S. energy consumption is expected to increase from 76.3 quadrillion Btu's in 1980 to 88.6 quadrillion Btu's in 1990. Figure 2 and Table 1 present these data, as well as the historical and projected total energy consumption per dollar of real GNP.

Figure 3 and Table 2 present a comparison of U.S. energy consumption by type of energy. Oil and gas combined are expected to constitute a declining absolute volume, as well as a decreasing percentage of the projected total U.S. energy consumption. Thus, the projected consumption of oil and gas is

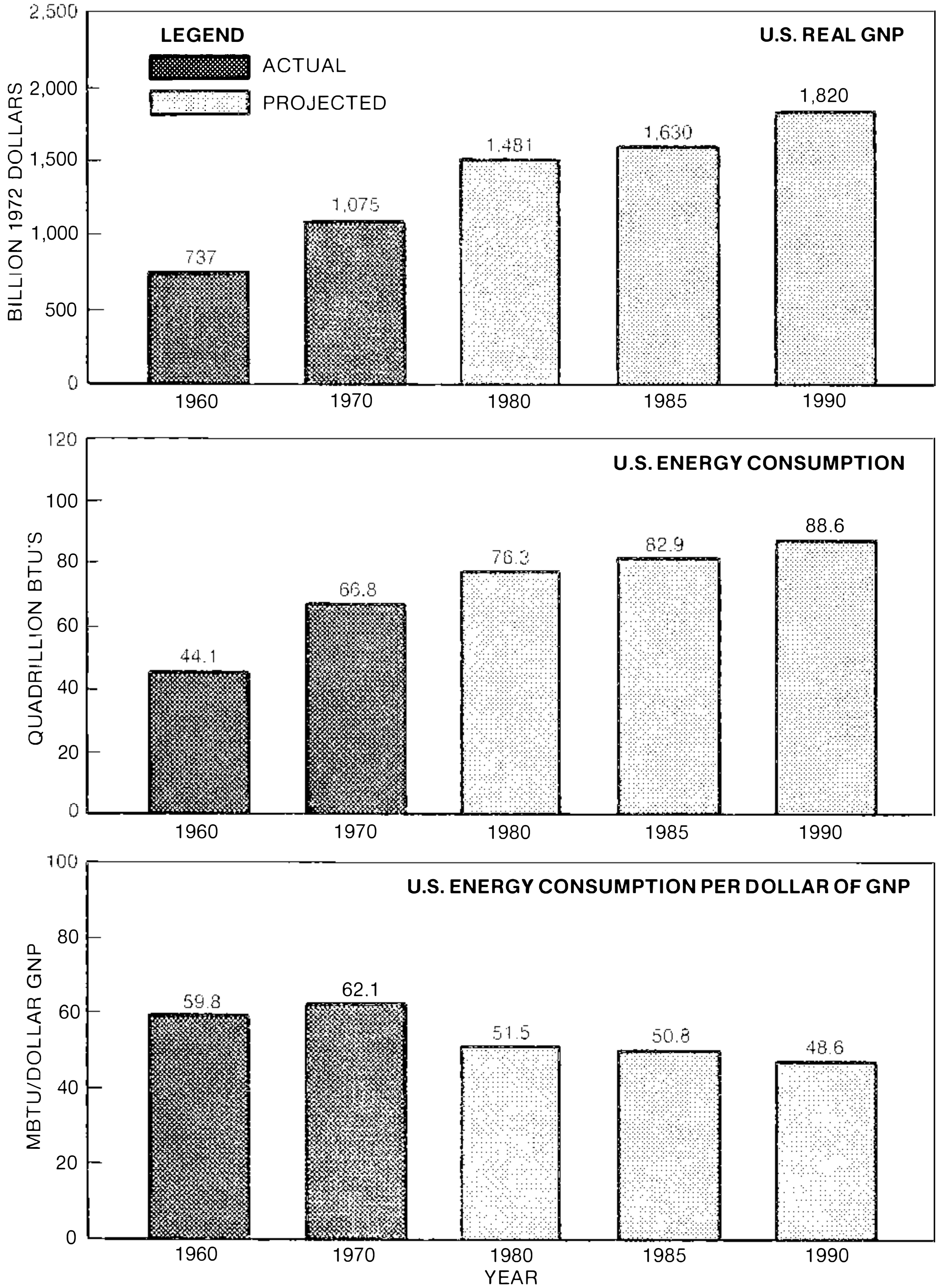


Figure 2. U.S. GNP and Energy Consumption Projections to 1990.

NOTE: Actual energy consumption data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Actual GNP data from U.S. Department of Commerce, Bureau of Economic Analysis. Projected data from National Petroleum Council, *Refinery Flexibility*, 1980.

TABLE 1

U.S. ENERGY CONSUMPTION AND GROSS NATIONAL PRODUCT*

	Total Energy (Quadrillion Btu's)	GNP (Billion 1972 Dollars)
Actual 1960 Data	44.10	737
Actual 1970 Data	66.83	1,075
Actual 1980 Data	76.26	1,481
1985 Projection	82.92	1,630
1990 Projection	88.59	1,820
	Annual Growth Rate (Percentage)	
Actual 1960-1970 Data	4.2	3.8
Actual 1970-1980 Data	1.3	3.3
1980-1985 Projection	1.6	1.9
1985-1990 Projection	1.3	2.2
1970-1990 Projection	1.4	2.7

*Actual energy consumption data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Actual GNP data from U.S. Department of Commerce, Bureau of Economic Analysis. Projected data from National Petroleum Council, *Refinery Flexibility*, 1980.

expected to decline by 2.4 percent in this decade, compared to the 58.3 percent increase from 1960 to 1970 and the 6.4 percent increase from 1970 to 1980. The percentage of oil and gas consumption to total energy consumption is also expected to decline in this decade, from 71.6 percent of total energy consumption in 1980 to 60.1 percent in 1990.

U.S. Petroleum Supply

Figure 4 and Table 3 compare the supply projections of domestic liquids production (crude oil and condensate and natural gas liquids) with petroleum imports to 1990. The 1980 NPC survey indicated that conventional liquids production is projected to decline sharply, from 10.2 million barrels per day (MMB/D) in 1980 to 8.5 MMB/D in 1990. Synthetic crude oil production is projected to increase from zero in 1980 to 0.5 MMB/D in 1990.

Total U.S. imports (crude and unfinished oils, and finished products and natural gas liquids) are expected to increase from 6.8 MMB/D in 1980 to 7.5 MMB/D by 1990, with approximately the same crude oil/product proportions as in 1980—three-quarters crude oil, one-quarter products.

U.S. Petroleum Demand

The projected 1990 total U.S. petroleum demand presented in Figure 5 and Table 4 reflects the conservation of resources and the shift in energy raw materials resulting from the political and economic events of recent years. Total U.S. petroleum demand is expected to remain fairly constant, although the economy as measured by the GNP is expected to grow. The demand will decrease from its peak of 18.8 MMB/D in 1978 to 16.8 MMB/D in 1990.

The most significant decline in the outook for future U.S. product demand occurs in the demand for residual fuel oil, which is expected to decrease approximately 44 percent over the next decade. While the amount of high-sulfur residual fuel oil as a percentage of total residual fuel oil demand is expected to increase by 2 percent, the absolute volume is virtually half of the 1980 level.

Also, demand for middle distillates (kerosine and heating oil No. 1, kerosine-type jet fuel, and distillate fuels) is projected to remain essentially constant over the decade; motor gasoline demand is expected to decrease from a high of 7.4 MMB/D in 1978 to 6.0 MMB/D in 1990, of which only 0.5 MMB/D is anticipated to be leaded.

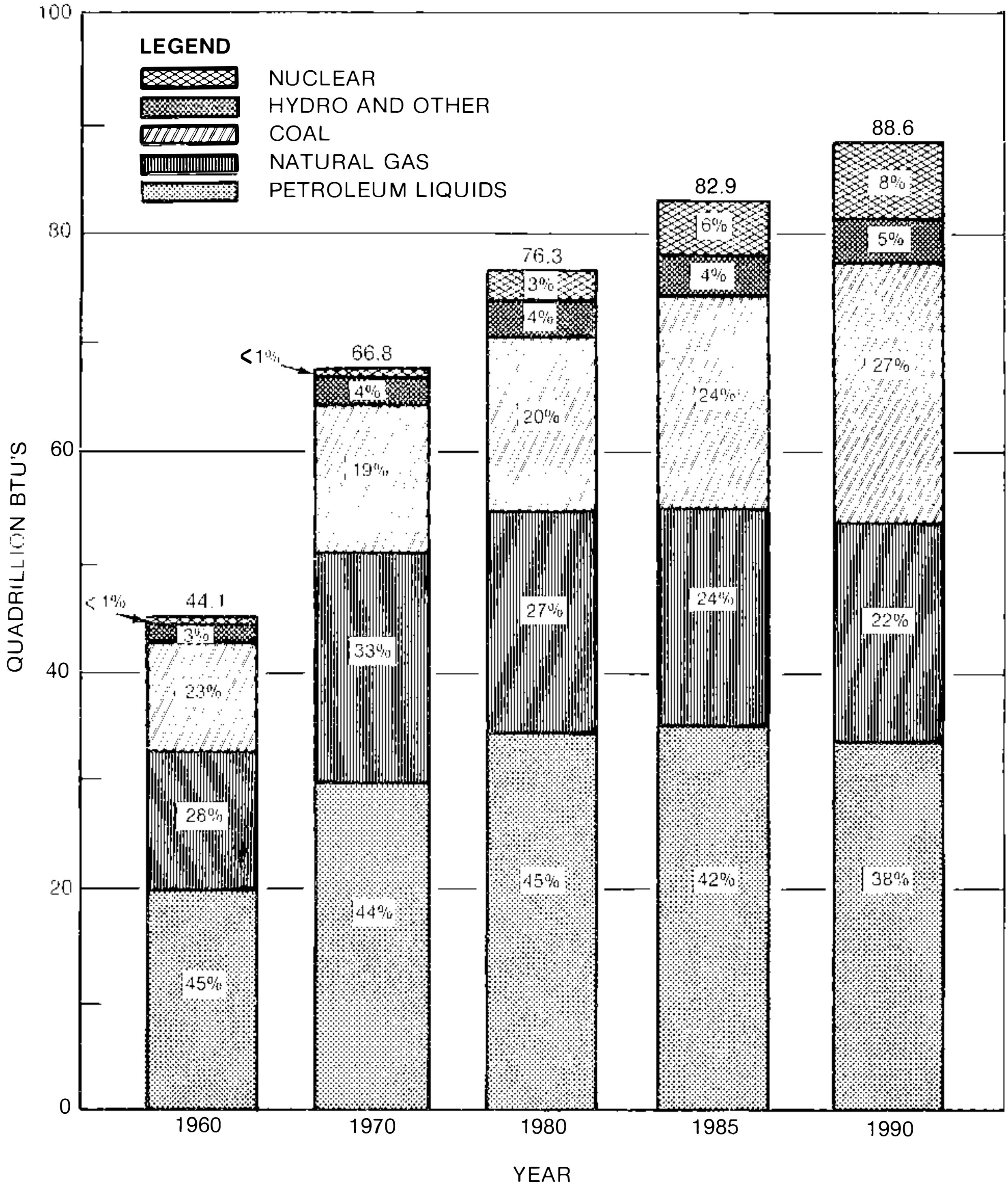


Figure 3. U.S. Energy Consumption by Type of Energy.

NOTE: Actual data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Projected data from National Petroleum Council, *Refinery Flexibility*, 1980. Percentages are share of total consumption in year shown.

TABLE 2

U.S. ENERGY CONSUMPTION—1960-1990*

	Actual 1960†	Percentage of Total	Actual 1970†	Percentage of Total	Actual 1980†	Percentage of Total	Projected 1985†	Percentage of Total	Projected 1990†	Percentage of Total
Petroleum	20.0	45.3	29.5	44.2	34.2	44.8	34.9	42.1	33.7	38.0
Natural Gas	12.4	28.1	21.8	32.6	20.4	26.8	19.5	23.5	19.6	22.1
Subtotal	32.4	73.4	51.3	76.8	54.6	71.6	54.4	65.6	53.3	60.1
Coal	10.1	23.0	12.7	19.0	15.7	20.6	19.5	23.5	24.2	27.3
Nuclear	0.0	< 1	0.2	< 1	2.7	3.5	5.3	6.4	7.0	7.9
Hydro and Other	1.6	3.6	2.6	3.9	3.2	4.2	3.6	4.3	4.1	4.6
Total	44.1	100.0	66.8	100.0	76.3	100.0	82.9	100.0	88.6	100.0

*Actual data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Projected data from National Petroleum Council, *Refinery Flexibility*, 1980. Totals may not add due to rounding.

†Quadrillion Btu's.

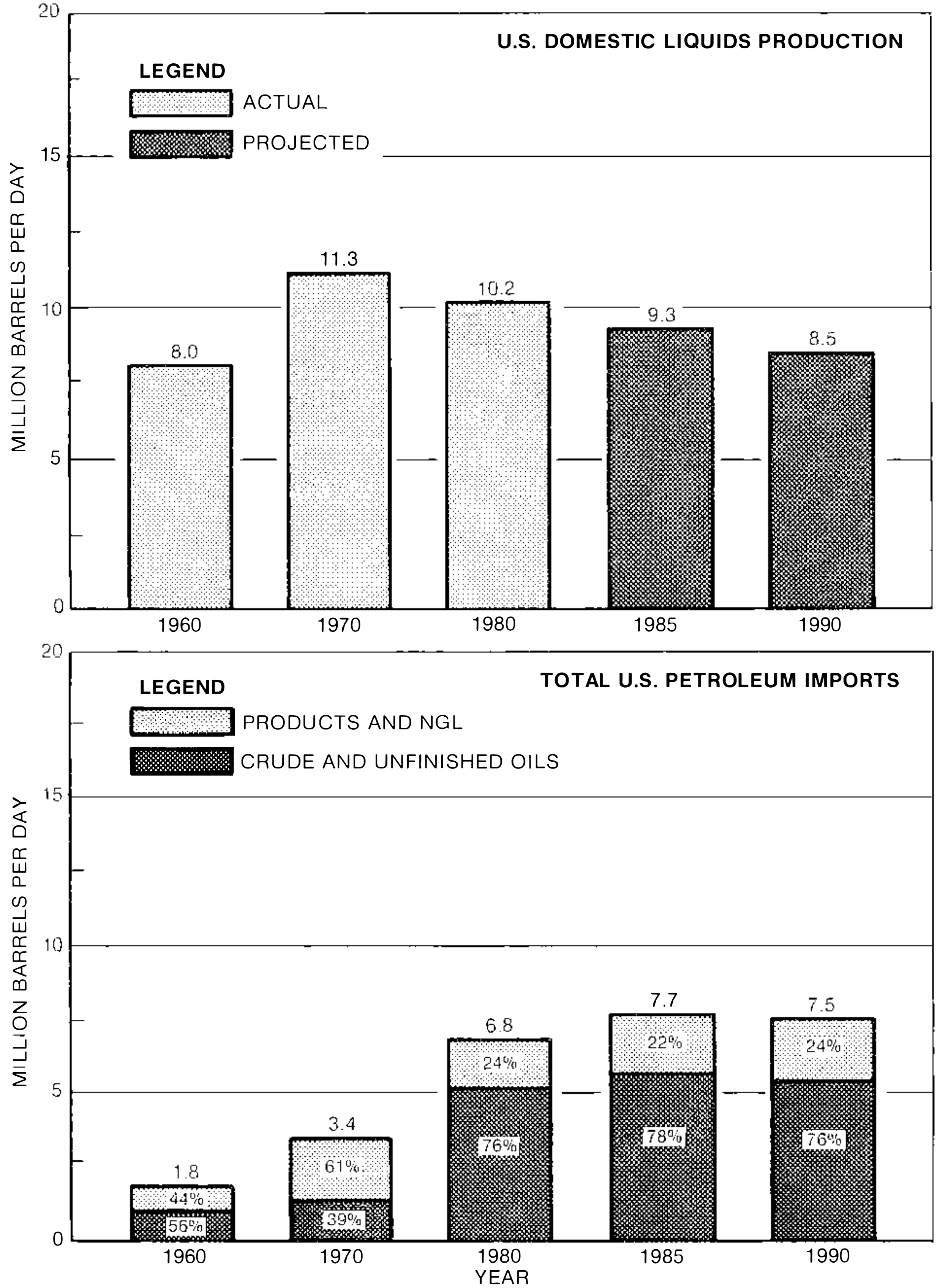


Figure 4. U.S. Liquids Production and Petroleum Imports.

NOTE: Actual data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Projected data from National Petroleum Council, *Refinery Flexibility*, 1980. Percentages are share of total imports in year shown.

TABLE 3

U.S. PETROLEUM SUPPLY*
(MMB/D)

	Actual			Projected	
	1960	**1970**	**1980**	**1985**	**1990**
Domestic Production					
Crude Oil and Condensate	7.1	9.6	8.6	8.0	7.5
NGL	0.9	1.7	1.6	1.2	1.0
Syncrude Production	0.0	0.0	0.0	0.1	0.5
Subtotal	8.0	11.3	10.2	9.4	9.0
Imports					
Crude and Unfinished Oils	1.0	1.3	5.2	6.0	5.7
Products and NGL	0.8	2.1	1.6	1.7	1.8
Subtotal	1.8	3.4	6.8	7.7	7.5
Processing Gain and Stock Change	0.2	0.3	0.6	0.5	0.5
Total Petroleum Supply	10.0	15.0	17.6	17.6	17.0

*Actual data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Projected data from National Petroleum Council, *Refinery Flexibility*, 1980. Columns may not add due to rounding.

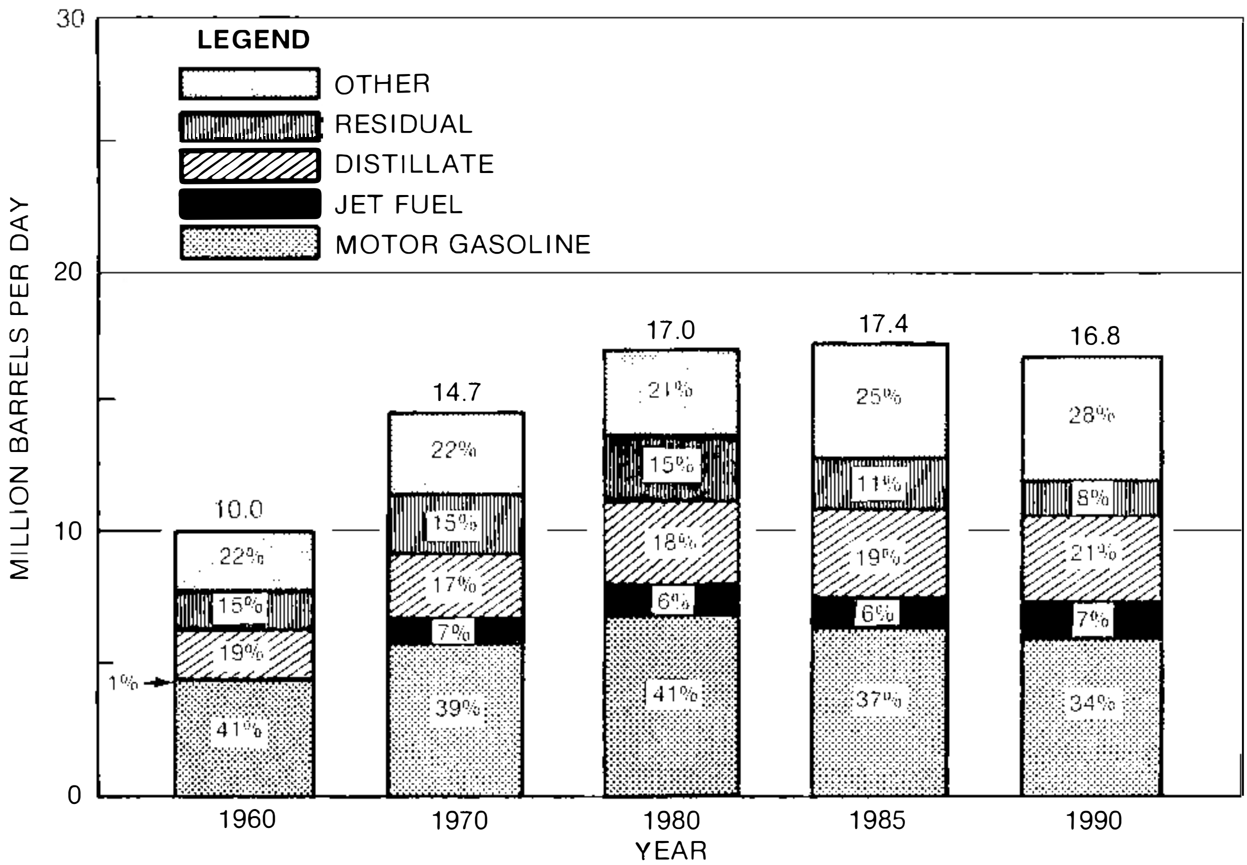


Figure 5. U.S. Domestic Petroleum Demand.

NOTE: Actual data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Projected data from National Petroleum Council, *Refinery Flexibility*, 1980. Percentages are share of total demand in year shown.

TABLE 4

TOTAL U.S. DEMAND FOR PRODUCTS—1960-1990*
(MMB/D)

	Actual			Projected	
	1960	**1970**	**1980**	**1985**	**1990**
Motor Gasoline	4.1	5.8	6.9	6.5	6.0
Jet Fuel	0.3	1.0	1.1	1.1	1.2
Distillate Fuel Oil	1.9	2.5	3.0	3.4	3.5
Residual Fuel Oil	1.5	2.2	2.5	2.0	1.4
Other	2.2	3.2	3.5	4.4	4.7
Total Domestic Demand for Products	10.0	14.7	17.0	17.4	16.8

*Actual data from Energy Information Administration, *1980 Annual Report to Congress*, Volume II. Projected data from National Petroleum Council, *Refinery Flexibility*, 1980.

Legislative and Regulatory Considerations

During the 1970's, government laws and regulations at all levels (federal, state, and local) placed an extraordinary number of constraints on the petroleum industry as well as on all the basic industries in the national economy. Those key laws that have a major impact on the petroleum industry are discussed below, as are the principal international marine conventions to protect the environment.

National

No other domestic policy challenges of recent times have been addressed by all levels of government as forcefully, quickly, and successfully as have the tasks of reducing the degradation of the U.S. environment and preserving its pristine areas. Since the NPC's 1971 report on this subject, the United States has entered into a long-term commitment to restore and protect the quality of the environment. Following the passage of the National Environmental Policy Act of 1970 (NEPA) at the start of the decade, some 43 other major environmental laws and amendments to those laws have been enacted, along with a number of others that are keyed to specific problem areas. Appendix C lists those laws by year of passage.

Beginning in the early 1970's, Congress increased the federal authority in pollution control and environmental protection. During this period, Congress also began to pass laws that established technology-based guidelines and technology-forcing provisions, in spite of the fact that the technologies were not fully developed. Industry was faced with the problem of equipping new and existing industrial plants with pollution control facilities whose reliability and efficiency had not yet been demonstrated.

In order to understand the breadth and complexity of the key laws passed during the 1970's, and to achieve an appreciation of the interactions and multiplying effects, the following laws and their key aspects are discussed below:

- National Environmental Policy Act
- Clean Air Act
- Clean Water Act
- Safe Drinking Water Act
- Resource Conservation and Recovery Act
- Comprehensive Environmental Response, Compensation and Liability Act
- Endangered Species Act.

It is intended that this list be viewed without priorities in mind—it is simply a listing of those statutes that represent major impacts on petroleum operations. The environmental considerations sections of this report address these and other laws and regulations specific to industry segments.

A number of key federal statutes and regulations impinge more directly on the petroleum industry operations in Alaska and they have been addressed in the NPC's 1981 report, *U.S. Arctic Oil and Gas*. The following are of particular interest to Alaska:

- Alaskan National Interest Lands Conservation Act
- National Petroleum Reserve-Alaska Leasing Act
- Department of the Interior's Fiscal 1981 Appropriations Act.

National Environmental Policy Act

The National Environmental Policy Act of 1970 set forth a national policy "to encourage harmony between man and his environment, to promote efforts to prevent or eliminate damage to the environment and promote the health and welfare of man, to encourage a better understanding of ecological systems and natural resources that are important to the nation, and to create a Council on Environmental Quality."

A key element of NEPA is its action-forcing provision—the requirement that no major federal action affecting the environment may be taken by a federal agency until it has analyzed the environmental consequences of the proposed action and possible alternatives. Not all federal agency actions require an environmental impact statement (EIS). Some important actions, such as the granting of a PSD permit, are exempt from the coverage of NEPA. Agencies also have the authority to make a finding after a brief environmental assessment that a proposed action will have no significant impact and prepare no further analysis. In addition, some important petroleum industry permits such as onshore drilling permits normally require only an environmental assessment, if there is no finding of significant impact. But where no exemption applies and there is some impact, an EIS must be prepared. Although some large projects have been approved without an EIS, it is nearly certain that any major energy project will involve at least one "major federal action," necessitating preparation of an EIS. Regardless of what triggers the EIS, the environmental analysis must cover the entire project and all of its impacts, not just the specific activity that may have forced the review.

The preparation of an EIS is a time-consuming process. The EIS must examine the environmental impact of the proposed action, adverse environmental effects that cannot be mitigated, alternatives to the proposed action, the relationship between short- and long-term benefits and costs, and irreversible commitments of resources associated with the proposed action. NEPA is essentially a procedural statute; where an EIS is necessary, it must be prepared in accord with a strict set of procedures. Early in the process, the agency must publish a notice of intent to prepare an EIS and invite public input to determine the scope of issues that will be addressed. After that, a draft EIS will be prepared and made publicly available. The agency must hold hearings on the proposal and the draft. Comments made on the draft by any party must be specifically addressed in the final EIS. Agency action on the proposed permit or other action cannot be made before publication of the final EIS and preparation of the public record of decision, indicating the factors that lead to its final choice. If an agency fails to meet the procedural requirements of NEPA, any party may go to federal courts and obtain an injunction preventing action until an adequate EIS has been prepared. NEPA legal suits rarely involve the merits of the proposed project, but rather turn on the question of whether a federal agency has met procedural requirements.

Preparation of an EIS, with its concomitant data collection and public hearings, may take between one and two years. This delay generally increases the project's costs. Although this activity has been incorporated into most of the planning processes, the delay can become critical at times and can add to the uncertainty of certain high-risk projects.

The methodology of EIS preparation often results in an examination of worst-case scenarios and other conjectural impacts, which may paint an unduly distorted picture of the likely hazards actually associated with the project. This can result in turning public opinion against the project. Utilization of proper risk techniques would provide a more balanced picture of the likely case.

Clean Air Act

The federal government first assumed responsibility for controlling air pollution under the Air Pollution Control Act of 1955. This Act was then amended by the Clean Air Act of 1963 and the Air Quality Act of 1967. Further amendments were added in 1970 and 1977. The 1970 amendments to the Clean Air Act formed the foundation for the nation's present approach to air quality management by establishing the requirement that NAAQS (designed to protect public health and welfare) for pervasive pollutants be attained and maintained at all locations in the country. The

1970 amendments stipulated further protection of existing air quality by requiring the use of best available controls of pollutants at all new facilities. The PSD policy, codified into law in 1977, requires that geographic areas whose air quality is already better than NAAQS for a particular pollutant shall be protected against "significant deterioration" of that quality. Only a small increment, if any, of a NAAQS can then be added to the atmospheric burden of the pollutant under consideration in that area. The 1970 amendments also required that SIPs be developed to ensure compliance with the NAAQS and subsequently the PSD requirements. Visibility protection in large national parks, international parks, and wilderness areas was provided by the 1977 amendments.

In 1971, EPA established NAAQS for six criteria pollutants: SO_2, TSP, CO, NO_x, oxidants, and non-methane hydrocarbons as an oxidant control method. Except for two changes, the initial standards have remained unaltered: deletion of the 24-hour and annual average secondary standards for SO_2; and redesignation of the oxidant standard to ozone [also made less stringent (0.08 to 0.12 parts per million)]. In 1978, a lead standard was adopted by EPA.

The 1977 amendments to the Clean Air Act required EPA to re-examine the NAAQS by December 31, 1980, and to re-examine each NAAQS every five years thereafter. This ongoing review of the NAAQS is an important activity relative to the nation's air pollution control program; any change in a standard could potentially affect other Clean Air Act requirements since all stationary source requirements have been designed to provide for compliance with the standards. In this way, the NAAQS are pivotal to the specific control strategies defined in the Clean Air Act.

EPA has responsibility for developing and promulgating the NAAQS, and primary (health-related) standards are to be based on current scientific knowledge concerning all identifiable health effects associated with a pollutant (which are summarized in a "criteria document"). Primary standards are established at a level intended to protect even the most sensitive members of the population and to provide, in addition, an "adequate margin of safety" below that level. Further, all but the annual standards can be exceeded only once per year. Therefore, the standards incorporate several factors of conservatism. Finally, the Clean Air Act specifically omitted costs from the factors EPA must consider in establishing the health-related standards. At present, there is considerable debate in the scientific and regulatory communities as to the form of the current standard-setting process and the basis for the specific numerical standards, including the margin of safety concept. These issues are presently under scrutiny by diverse groups in the public and private sectors. Setting NAAQS is one of the key issues of the 1980's discussed in Chapter Three.

As part of its review, EPA has reviewed the oxidant standard, altered the level, and changed the standards to incorporate specifically only ozone as the surrogate, as mentioned above; reviewed the CO standard; and indicated that it plans to eliminate the hydrocarbon standard.

In addition, EPA is currently revising the criteria documents for TSP and SO_2. Changes to these standards may result from the ongoing reviews of health effects research. The first draft of the revised criteria document was reviewed by the Clean Air Scientific Advisory Committee (CASAC) of EPA's Science Advisory Board, at a public meeting in August 1980. Concern was expressed regarding deficiencies in the scientific bases for the TSP standard at that time. The TSP standard in its current form is considered by some CASAC members to be inadequate for the protection of public health and welfare, because the health effects of particles are suspected to be directly related to their size and chemical compositions. Neither of these properties is reflected in the current standards, which are based solely on mass concentration. Therefore, EPA is considering separate standards relating to sulfate particulates and inhalable particulate material. EPA has an extensive health effects research program in progress related to fine particulates, but major epidemiological components of the program will require several years for completion.

The 1970 amendments to the Clean Air Act specified that all states were to attain the primary NAAQS by May 31, 1975 (in limited cases, an extension to July 1977 was possible); secondary standards were to be attained within a "reasonable period of time," generally within three years of primary NAAQS attainment. (The 1977 amendments to the Clean Air Act subsequently required attainment of the primary standards by 1982, with possible extension to 1987 for ozone and CO.) However, due to problems in achieving the NAAQS in many areas of the country, EPA developed an Emissions Offset Policy in December 1976, which was subsequently incorporated in Part D (Nonattainment) of the Clean Air Act as amended in 1977. This policy states that

major new and expanded sources must offset any projected emissions increases with even greater corresponding reductions in emissions in the area of proposed source location.

As the United States seeks to develop domestic oil and gas supplies in the next decade, various facilities subject to air quality regulations will be developed. These developments include modifications to existing facilities and construction of new capacity in "grassroots" or greenfield areas (generally lacking supporting infrastructure) and at more developed sites. The specific procedures or pre-construction reviews of major oil and gas facilities are dependent upon the attainment status of the NAAQS for each pollutant to be emitted in significant quantity by the facility. Where the NAAQS are not being attained, the facility owner/operator must comply with the pre-construction review procedures governing nonattainment; where the NAAQS are being attained, the facility owner/operator must comply with the pre-construction review procedures governing PSD areas. Occasionally, a single facility will be subject to both sets of pre-construction review procedures (e.g., where an area is designated as nonattainment for one or more pollutants and attainment for other pollutants).

The total permit preparation and processing time for major new and modified facilities is frequently 22 to 48 months. Of that time, EPA averages only 8 1/2 months for its review and approval of the permit, including public hearings, due in part to EPA's implementation of a high-priority system for energy-related projects. Such detailed pre-construction review often results in delay and uncertainty, which can increase the risks of capital investment and of the ultimate viability of projects. Recent studies have indicated that the pre-construction review process could be simplified, thereby allowing significant cost and time savings in improving the efficiency and certainty of industrial planning and development.[1] In the case of the oil and gas industries, improvement of the pre-construction review process is critical as efforts to develop and produce energy intensify in this decade.

Prevention of Significant Deterioration. The national goal to preserve air quality in less polluted regions (i.e., prevent significant deterioration of air quality) was explicitly codified into Part C of the Clean Air Act in August 1977. The stated purposes of the PSD policy are to preserve the special air quality characteristics of national parks and other identified areas, and to allow moderate growth of well-controlled facilities at suitable locations in other clean air areas. To meet this goal, the PSD rules establish emission control and siting requirements on all new and expanded major emitting facilities in clean air areas. These rules can limit the size of individual plants as well as the total number of sites potentially suitable for industrial development. Three classes of clean air areas have been established and maximum increases of SO_2 and TSP concentrations have been specified for each area. These incremental values (expressed in micrograms per cubic meter) are small percentages of the related NAAQS for each pollutant. Control of air pollution through the PSD policy, therefore, by definition goes well beyond the control levels needed to protect public health.

PSD in the past has created substantial technical and administrative uncertainties and delays in major plant construction in the country. A serious case is its potential impact on energy resource development in the West, if the allowable increments are fully utilized.

The PSD provisions of the 1977 amendments introduced:

- Formal designation of attainment (PSD) areas.
- More stringent PSD increments for SO_2 and TSP (than EPA's 1974 regulations) in Class II and III areas.
- Mandatory designation of Class I areas for the following areas in existence as of August 7, 1977: international parks, national wilderness areas, and memorial parks larger than 5,000 acres; and national parks larger than 6,000 acres. There are 158 Class I areas nationwide.
- Expansion of the number of source categories subject to PSD pre-construction review from 19 to 28. Petroleum refineries and fuel conversion plants are two of the 28 specified source categories.
- A "two-tier" system, which was established for PSD pre-construction review. Major new and modified stationary sources within the 28 specified categories are subject to PSD review if they have the potential to emit 100 tons or more per year of any pollutant regulated under the Clean Air Act. The emission threshhold for stationary sources other than the 28 specified is 250 tons per year.
- Increased application of BACT to all pollutants regulated under the Act. In addition, BACT is to be determined on a case-by-case basis and must be at least as stringent as the applicable NSPS.

- More sophisticated modeling and monitoring requirements to demonstrate compliance with the increments (and ambient standards).
- Specific air quality and meteorological monitoring requirements were added to the PSD review process.
- Requirements for additional analysis of impacts associated with a proposed new source or modification of air quality related values were added.
- Additional PSD provisions, which were to be developed by August 7, 1979, for the other criteria pollutants. PSD rules for lead were to be promulgated by October 5, 1980.

On June 19, 1978, EPA promulgated regulations, issued in two parts, to implement the PSD program established by the 1977 amendments. The 1978 PSD regulations were challenged by both industry and environmental groups in *Alabama Power vs. Costle*, heard by the U.S. Court of Appeals for the District of Columbia Circuit. On June 18, 1979, the federal court released a preliminary decision and entertained petitions for reconsideration of some issues. Meanwhile, to expedite the regulatory process governing pre-construction review, EPA responded to the court's initial decisions with proposed major amendments to the PSD regulations on September 5, 1979. On December 14, 1979, the court issued its final opinion, but stayed the effect of the decision pending EPA's program for final implementation of its mandate. As a result of the court's opinion, the final PSD regulations were ultimately promulgated by EPA on August 7, 1980.[2]

Nonattainment. Part D of the Clean Air Act, as amended in 1977, establishes specific provisions to permit limited industrial growth in areas of the country designated as nonattainment, in order to foster simultaneous improvement in air quality. A nonattainment area is a bounded region in which air quality levels do not comply with the NAAQS for one or more pollutants based on valid monitoring data and/or air quality modeling results. On March 3, 1978, EPA published its first list delineating the attainment status of areas throughout the country. This list is updated (usually at the state's initiative), as the air quality in each area improves, degrades, or the designation is changed by new data.

Under the Clean Air Act, states were required to revise their SIPs by January 1, 1979 (with EPA review to be completed by July 1, 1979), to include detailed strategies for bringing nonattainment areas into compliance by December 31, 1982 (the attainment date was extended to 1987 in limited cases). The Act further authorizes EPA to impose no-growth sanctions in areas of states or territories for which there is no approved SIP. As of May 1981, a total of 31 states and one territory had no approved SIP for at least one pollutant. To date, EPA has imposed moratoriums on construction of major new or modified facilities in portions of over 30 states and several major source permits have been delayed.

Major new and modified sources proposed for location in nonattainment areas or having an impact on nearby nonattainment areas are subject to the requirements listed below:

- Lowest Achievable Emission Rate
- SIP compliance or an approved plan for compliance of all sources owned by the applicant within the state
- Offsets greater than one to one
- Positive net air quality benefit.

The complexity of these requirements adds to the time, cost, and uncertainty of obtaining the necessary permits. The availability of satisfactory offsets might become critical in facilities and areas that are already heavily controlled in attempts to meet NAAQS. Collectively, these may cause viable energy projects to be cancelled while still in the planning stage.

Future Amendments to the Clean Air Act. Modification of the PSD and nonattainment provisions of the Clean Air Act may result from Congressional review pursuant to reauthorization of the Act. Many industry groups, environmental organizations, and local, state, and federal government entities have prepared proposals for Congressional consideration. While there is great diversity in these proposals, there is wide support for simplifying the permit review process.

The NPC believes that modifications to the Clean Air Act could alleviate some of the problems inherent in the existing PSD and nonattainment permit review requirements and could improve the certainty and efficiency of the planning and development processes for new and expanded sources in the petroleum industry. The following issues should be considered in any future amendments to the Clean Air Act:

- Setting of NAAQS based on valid scientific studies subject to peer review
- PSD increments, including disposition of Class II and III increments

- Emissions offset requirements in nonattainment areas
- Pre-construction permit process
- Scope of visibility protection requirements
- Use of cost-effectiveness and/or cost-benefit analyses as the basis for specific legislative provisions and implementing regulations
- Federal sanctions in nonattainment areas.

Clean Water Act

The 1972 amendment to the Federal Water Pollution Control Act expanded an existing federal role in water pollution control. It expanded water quality standard programs initiated in 1965 and extended the national program to all navigable waters in the United States. It created a system of uniform national technology-based effluent limitations, or more stringent limitations if required, to meet water quality standards. It instituted a national permit system for all point source discharges, and specific deadlines were established for achieving those effluent limitations based on designated control technologies. Two general goals were proclaimed: to achieve, wherever possible, by July 1, 1983, water that is clean enough for swimming and other recreational uses, and clean enough for the protection and propagation of fish, shellfish, and wildlife; and by 1985, to have no discharge of pollutants into the nation's waters.

The Clean Water Act Amendments of 1977 made major mid-course corrections to the 1972 law and incorporated many of the provisions of a previous court settlement on toxics control, adding new emphasis to the control of the discharge of toxic pollutants. It divided pollutants into three classes—conventional, nonconventional, and toxic—and different discharge requirements were established for each class. Additional pretreatment requirements were established for discharges to municipal sewage treatment systems and EPA was authorized to control the runoff of toxic and hazardous materials from industrial sites through Best Management Practices.

The 1978 amendments to the Clean Water Act specifically revised provisions dealing with Section 311 discharges of oil and hazardous substances. These issues included the determination of harmful quantities, penalties, and exclusion for hazardous substance discharges regulated under NPDES permits.

The four principle sections of the Act that have direct impact on the petroleum industry are: Section 402, National Pollution Discharge Elimination System; Section 404, permits for dredge or fill material; Section 311, oil and hazardous substances liability; and Section 401, governing state certification of federal permits for discharges originating in state waters.

NPDES Permits. The Clean Water Act prohibits the discharge of any pollutants, except as authorized by an NPDES (or other) permit. Each NPDES permit required compliance with effluent limitations by July 1, 1977, reflecting the Best Practicable Control Technology Currently Available (BPT). By July 1, 1984, NPDES permit effluent limitations further require application of the Best Available Technology Economically Achievable (BAT) for toxic and nonconventional pollutants and the Best Conventional Pollutant Control Technology (BCT) for conventional pollutants. The Clean Water Act provides for waivers from BAT for nonconventional pollutants in some cases. New sources are required to comply with NSPS, which reflect the greatest degree of effluent reduction achievable through application of Best Available Demonstrated Control Technology, processes, operating methods, and other alternatives including, where practicable, a standard permitting no discharge of pollutants.

U.S. Army Corps of Engineers Permits. Section 404 permits are issued by the U.S. Army Corps of Engineers for the discharge of dredge or fill material into the navigable waters. Guidelines for permit issuance are developed by EPA based upon criteria comparable to the criteria applicable to the territorial seas and oceans. EPA, a state, or an adjacent state may add stipulations to the Section 404 permit or prohibit its issuance. The EPA may withdraw the permit for a disposal site for dredge or fill material whenever it determines, after a public hearing, that the discharges will have an unacceptable adverse effect on the receiving waters. To understand the real significance of expanded review authority of the Corps of Engineers for such permits, one must look at the related legislation that impacts on the permitting decisions of the Corps.

- Section 401 of the Clean Water Act requires certification from the state in which the discharge originates that the discharge will comply with the applicable effluent limitation and water quality standards.
- Section 307 of the Coastal Zone Management Act requires an applicant to furnish a certification that the proposed activity will comply with the state's CZM program. No permit will be issued until the state has concurred with the applicant's certification.

- Section 302 of the Marine Protection Research and Sanctuaries Act authorizes the designation of marine sanctuaries. Activities in the sanctuaries authorized by the Corps of Engineers are valid only if the Secretary of Commerce certifies that the activities are consistent with the purposes of the Act and can be carried out within the regulations for the specific sanctuaries.
- NEPA may require an EIS when several Corps of Engineers permits are issued in one specific area. An EIS may also be required by an application for a permit that results in a major federal action in the opinion of the Corps.
- The Fish and Wildlife Act requires that before the Corps of Engineers issues any permit that proposes to control or modify any body of water, the Corps must first consult the U.S. Fish and Wildlife Service, the National Marine Fishery Service, as appropriate, and the head of the appropriate state agency exercising administration over the wildlife resources of the affected state.
- The National Historical Preservation Act authorizes that its advisory council review activities licensed by the Corps that will have an effect upon properties listed in the National Register of Historical Places or eligible for such listing.
- The Preservation of Historical and Archaeological Data Act provides that the Corps of Engineers may delay granting a permit if the permitted activity would alter any terrain such that significant historical or archaeological data are threatened, until the Secretary of the Interior takes action necessary to recover and preserve the data.
- The Endangered Species Act provides that the Corps of Engineers must utilize its authorities by carrying out programs for the conservation of endangered or threatened species and by taking such action as is necessary to ensure that any action authorized by the Corps will not jeopardize the continued existence of such species or result in the destruction or adverse modification of the habitat of such species.
- The Marine Mammal Protection Act of 1972 imposes a perpetual moratorium on harassment of marine mammals and has the potential for preventing the issuance of a Corps permit.
- The Wild and Scenic Rivers Act provides that the Corps of Engineers shall not assist by permit or otherwise in the construction of any water resources project that would have a direct and adverse effect on the values for which a river was designated a wild and scenic river.
- In addition to all of these, where an application affects wetlands, the District Engineer of the Corps may undertake reviews of particular wetland areas in consultation with the appropriate regional director of the Fish and Wildlife Service, the National Marine Fishery Service, the National Oceanic and Atmospheric Administration, the Regional Administrator of EPA, local representatives of the Soil Conservation Service of the Department of Agriculture, and the head of the appropriate state agency to assess the cumulative effect of activities in such areas.

Oil and Hazardous Substance Spills. The Clean Water Act prohibits the discharge of oil or hazardous substances, in quantities that may be harmful, into or upon the navigable waters of the United States. A new National Contingency Plan is required for the removal of oil and hazardous substances and is now expected to be published in 1982. This plan will assign duties and responsibilities among federal departments and agencies in coordination with state and local agencies. Regulations are specified to cover methods of procedures for prevention of spills as well as of removal of any accidental discharges. Spillage of any designated material that may be harmful must be immediately reported to the National Response Center.

State Certification. The Clean Water Act also requires that NPDES permits contain conditions that ensure compliance with applicable state water quality standards or limitations. Under another section of the Act, EPA may not issue an NPDES permit until the state in which the discharge will originate grants or waives certification to ensure compliance with appropriate requirements of the Clean Water Act and state law. These stipulations frequently result in conflicts between the federal agency and the state agency with a resultant delay in the issuance of the final NPDES permit and the approval to construct a new facility or modify an existing facility with the necessary pollution control.

Safe Drinking Water Act

The Safe Drinking Water Act directs the establishment of two major regulatory programs. One program relates to public water systems and requires that EPA establish national primary and secondary drinking water standards for public water systems. This statute directs the primary enforcement responsibility to the states to ensure that

public water systems comply with the national standards. The other program, which has the larger impact on the oil and gas industries, relates to underground sources of drinking water, and it requires that EPA publish regulations for state underground injection control (UIC) programs. The UIC programs regulate the re-injection of produced waters from exploration and production operations, underground cavern storage of petroleum products, and underground injection of hazardous wastes. These regulations must establish minimum requirements for effective programs to prevent underground injection that endangers drinking water sources. These regulations are in addition to the requirements set by state regulatory agencies. Oil and gas producing states have developed and implemented very effective UIC regulations.

Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act provides a comprehensive program for the regulation of wastes. It greatly expands the role of the federal government in the field of waste disposal, with particular emphasis on the regulation of hazardous waste and resource recovery. The program is to be achieved through implementation of several programs: the establishment of a hazardous waste control program; a solid waste management program in each state, together with a prohibition on the practice of open dumping; and the encouragement, through federal aid, of state and regional waste management planning.

The statute allows states to apply to EPA for authorization to administer the hazardous waste program. EPA has issued regulations and has established minimum requirements for state hazardous waste programs in order to receive EPA approval.

Of particular interest to the petroleum industry is the regulation, from generation to final disposal, of hazardous wastes. EPA has promulgated regulations defining hazardous wastes, setting requirements for generators and transporters, and setting interim status standards for existing facilities that treat, store, and dispose of hazardous wastes. Final standards for hazardous waste management facilities are still being developed. The petroleum industry is affected primarily by the broad classification of hazardous wastes identified by EPA, which fails to distinguish between wastes that pose a lesser degree of hazard and such extremely hazardous materials as Kepone or dioxin. This classification system will result in secure disposal sites being used for waste with a low degree of hazard, thereby increasing the shortfall of needed capacity to dispose of truly hazardous waste.

An important question, primarily because of the potential financial impact on the industry, is whether EPA will determine that wastes associated with the drilling and producing sector of the petroleum industry should be covered by RCRA regulations. At the present time, wastes associated with petroleum and natural gas drilling and production are excluded from the definition of hazardous wastes. EPA does not anticipate completing the necessary research work in this area and the possible regulations until at least 1985. Compliance with the regulations proposed in December 1978 could have resulted in increased capital costs to the oil and gas drilling industry of $31 billion (in mid-1978 dollars) as well as increased annual direct operating and maintenance costs of $3.3 billion.[3]

In light of the concern that is expressed by the public and the difficulty in satisfying the EPA criteria for hazardous waste disposal sites, a great deal of difficulty is envisioned in the siting of hazardous waste disposal facilities and the subsequent operation of those facilities. The potential lack of facilities, especially in proximity to those facilities that generate most of the hazardous wastes, can lead only to very high transportation and administration costs.

One approach to the solution of the potential lack of disposal facilities is legislation to establish and control such facilities in a manner similar to that of public trusts. Private or publicly owned hazardous waste disposal corporations would be encouraged by appropriate federal and state legislation to establish and operate disposal sites on properly designated lands. Proper schedules of charges for disposal, together with a regulated profit margin, would be authorized. Proper compliance with construction, operation, maintenance, recordkeeping, and closure standards would be assured under terms of the site contract as well as regulatory provisions in the enabling legislation. After final closure, the land would revert to the federal and/or state government for stabilization and containment of the waste in perpetuity. Such an organization could assure the nation that hazardous wastes would be handled safely and in compliance with all applicable control requirements.

The Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act, or

"Superfund," establishes a federal fund to finance government action to prevent threatened releases of hazardous substances or to remedy the effects of past releases of such substances. It provides for strict liability on the part of owners and operators of vessels and waste disposal sites for the release of hazardous materials into the environment. Through imposition of an excise tax on crude oil, petroleum products, and 42 basic industrial chemicals, a $1.6 billion fund will be established to enable the government to pay cleanup costs resulting from releases of hazardous substances into the environment when the culpable party is unknown or unable to pay. The reporting requirements under the Act are expected to reveal the existence of hazardous waste disposal sites that are not regulated, i.e., not active under RCRA. Serious liability consequences may result to companies that are subsequently found to have used sites that are creating a danger to human health or the environment.

The ultimate effects of Superfund are somewhat less predictable for the petroleum industry than for some other industries at this point. The "deep pocket" approach, under which enforcement is pressed against the party most likely to be able to pay, regardless of the extent of culpability, could place an extreme liability on financially solvent generators of hazardous wastes. Such generators are assumed to bear a liability for correcting disposal site problems even though their only connection with the disposal operation is their contribution of wastes for disposal. The total impact of Superfund on the petroleum industry cannot be determined until the regulatory program is completed.

The Endangered Species Act

The Endangered Species Act mandates affirmative action to preserve endangered and threatened species. It declares that there is a public responsibility to prevent the extinction of species of fish, wildlife, or plants that would occur as a consequence of economic growth or development; and it encourages the states, through federal financial incentives, to develop and maintain conservation programs that work to meet this goal. It further provides that an entire ecosystem of a threatened species may be conserved, and declares that it is the policy of Congress that all federal departments and agencies shall seek to conserve endangered species and use their authorities in furtherance of the Act.

This law presents barriers to petroleum industry development because it is written in general language, providing the Executive Branch regulators with significant new powers but little or no operational guidance. The impact of the program has grown significantly in recent years. The entire ecosystem of an endangered species may encompass a vast amount of acreage or ocean that would be placed off limits to natural resource development. The list of endangered domestic flora and fauna contains approximately 300 species.

International Marine

Nations have a great interest in promoting a satisfactory quality of international waters both of the high seas and of international basin drainage systems. Pollution of the high seas endangers the quality and resources of the territorial waters of coastal nations and, of course, the shores as well.

Intergovernmental Maritime Consultative Organization

To serve as the institutional mechanism for establishing worldwide vessel standards, the Intergovernmental Maritime Consultative Organization (IMCO) was founded in 1959 under the auspices of the United Nations. Since its inception, IMCO has been primarily a maritime nation agency dealing with technical maritime problems. The costs of IMCO administration are divided among the maritime nations according to the tonnage of vessels flying each nation's flag. Non-maritime nations have a standing invitation to attend IMCO meetings, but few have done so and their voting power has not been substantial.

The following international conventions developed by or under the jurisdiction of IMCO relate to vessel safety and pollution prevention:

- Convention for Safety of Life at Sea (SOLAS), 1960 and 1974 (general life-saving requirements for vessels).
- International Convention on Load Lines, 1966 (established load limits).
- International Regulation for Preventing Collisions at Sea, 1971 (voluntary rules of the road).
- International Convention for the Prevention of Pollution of the Sea by Oil, 1954 (operation discharge standards and prohibited discharge zones), amended 1962, 1969, and 1971. All amendments except 1971 are in force.
- International Convention Relating to Intervention on the High Seas in Cases of Oil Pollution, 1971 (rights of a coastal nation to protect itself from a disabled vessel carrying oil).

- International Convention on Civil Liability for Oil Pollution Damage, 1969 (sets strict liability with limits for shipowners in cases of oil pollution).
- Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage, 1971 (creates an international fund to cover oil pollution damages beyond the liability of the shipowner).
- International Convention for the Prevention of Pollution From Ships, 1973—referred to as MARPOL 1973 (new discharge and construction standard treaty for all polluting substances designed to substitute for the 1954 Convention—not yet enforced).
- Tanker Safety and Pollution Prevention Conference of February 1978—referred to as MARPOL 1978 (requires segregated ballast tanks, dedicated clean ballast tanks, or crude oil washing equipment on existing and new vessels—not yet enforced).
- Standards of Training, Certification and Watchkeeping for Seafarers, 1978 (national licensing programs, and improvements in training, qualification, and certification for tanker personnel—not yet enforced).

International efforts to strictly control vessel-source pollution were actually initiated at the behest of the United States. A conference on the subject convened in 1926 in Washington, D.C., but a U.S. proposal for a total prohibition of oil discharges from ships was defeated two to one. It was not until 1954 that a convention was finally concluded—but without a discharge ban. International discharges were merely limited and enforcement was to be carried out by the flag-nation, using penalties it determined appropriate. Nations other than the flag-nation could inspect the vessel's oil record book (mandated by the 1954 Convention) only when it called at their ports and, if discrepancies were discovered, they would have to request the flag-nation to take enforcement action.

The discharge standards and prohibited zones were made more stringent in 1962. The 1969 amendments did away with zones altogether and limited the rate of discharge of oil even further. But the discharge standards adopted would still permit a 300,000 deadweight ton (DWT) tanker to discharge a maximum of 20 tons during the course of any one ballast voyage at a rate not to exceed 80 liters per mile.

The 1971 amendments to the 1954 Convention are more significant. For the first time, construction standards were developed to prevent or minimize oil outflow in the event of an accident. These requirements restrict cargo tank size as a means of limiting maximum oil outflow resulting from a tanker collision or grounding. The 1954 Convention and amendments were subsequently superseded by MARPOL 1973 and MARPOL 1978.

MARPOL 1973 was developed in London in November 1973, and represented the most comprehensive treaty on the subject to that time. Included were measures to control more pollutants than ever before and emphasis was put on prevention rather than cleanup and other post-accident measures. Briefly, the new treaty included the following salient features:

- Regulation of ship discharges of oil, various liquid substances, and harmful package goods
- Control, for the first time, of tankers carrying refined products
- Requirements for segregated ballast for all tankers over 70,000 DWT contracted for after December 31, 1975 (but does not require double bottoms)
- Prohibition of all oil discharges within 50 miles of land (as did the 1969 amendments)
- Mandate for all tankers to operate with the load-on-top system, if capable
- Reduction of maximum permissible discharge for new tankers from 1/15,000 to 1/30,000 of cargo capacity (Note: no total discharge prohibition)
- Regulation of the carriage of 353 noxious liquid substances with requirements ranging from reception facilities to dilution prior to discharge
- Control of harmful package goods in terms of packaging, labeling, stowage, and quantity limitations
- Prohibition of discharge of sewage within four miles of land unless the ship has an approved treatment plant in operation, and from 4 to 12 miles unless the sewage is macerated and disinfected. [4]

In the area of enforcement, the international legal status quo was modified to some degree. The flag-nation must punish ship owners for all violations. A coastal nation has the right (as well as the duty) to punish the owner of a foreign-flag vessel for violations occurring in its waters or to refer the violation to the flag-nation for prosecution. Nations that ratify the treaty must apply its terms to all vessels, including those flying flags of nations that do not sign the treaty, in order to prevent vessels of nonsignatory nations from gaining

competitive advantage. To settle any disputes, compulsory arbitration is a treaty requirement.

On the question of standard-setting authority, a provision was defeated that would have made the treaty provisions exclusive on subjects it addressed. Consequently, there are no treaty restrictions on the right of coastal nations to set more stringent requirements within their jurisdictional waters.

The MARPOL 1973 Convention must be ratified by at least 15 nations that, among them, represent at least 50 percent of the total tonnage in the world fleet. Since previous conventions required ratification by 32 nations, this represents a significant easing of the ratification process.

In mid-December 1976, the *Argo Merchant* ran aground and broke up near Nantucket, Massachusetts. In a little over three months there were 14 more tanker-related incidents off U.S. coasts. Of these, almost two-thirds were serious. Following these accidents, the President warned the world maritime community that the United States intended to ensure that the events of the winter of 1976-1977 would not re-occur. The Administration suggested that the United States would take unilateral action if necessary, but that it would prefer to join the international shipping community in improving tanker regulations and existing pollution prevention measures. In response to the President's initiatives, the Tanker Safety and Pollution Prevention Conference was convened in February 1978. The outcome of this IMCO conference was the adoption of amendments to SOLAS 1974 and MARPOL 1973. Because procedural constraints do not permit amendments to conventions that are not in force and neither SOLAS 1974 nor MARPOL 1973 had been ratified by the requisite number of states at the date of the convention, the conference results became "protocols" to these two conventions. The new requirements are as follows:

- SOLAS Protocol 1978
  - Improved inspection and certification procedures for all ships.
  - Inert gas systems for all new tankers of 20,000 DWT and over and existing tankers of 40,000 DWT or more.
  - Second radar on all ships over 10,000 gross registered tons (GRT). IMCO was obligated to prepare a performance specification for collision avoidance aids.
  - Improved emergency steering gear requiring two independent steering control systems for all tankers 10,000 GRT or more.
- MARPOL Protocol 1978
  - Protective location of segregated ballast tanks in the side and bottom shell areas for new tankers
  - Clean ballast tanks as an alternative to segregated ballast on product tankers by using dedicated cargo tanks only for clean ballast water
  - Crude oil washing to tankers of 20,000 DWT and over and as an alternative to segregated ballast for existing crude oil tankers of 40,000 DWT or more.

MARPOL 1973 and its 1978 Protocol are not yet in force; however, SOLAS 1974 has been in force since May 1980 and its 1978 Protocol came into force on May 1, 1981.

Recognizing the importance of the human element in mitigating pollution incidents on the seas, IMCO called a conference that resulted in an International Convention on Standards of Training, Certification and Watchkeeping for Seafarers, 1978. This conference was the first called to establish international standards for ships' officers and crews. Specifically, the Convention provides for the submission of national licensing programs and the exchange of data among parties, and it provides for the training, qualification, and certification of tanker personnel.

The status of IMCO-related international conventions is shown in Table 5.

Costs of Environmental Controls to the Petroleum Industry

The Past

The Secretary of Energy requested of the NPC information on the impact of environmental controls on the cost of petroleum products and natural gas. The API Annual Expenditure Survey describes and documents the cost to U.S. petroleum companies, representing 70 percent of U.S. refining capacity.[5] These costs are reported as spent and have not been extrapolated to include the nonreporting companies. The annual report shows the specific costs for the current 10-year period with a variety of parameters; i.e., total expenditures; capital expenditures; administrative, operating, and maintenance expenditures; and research and development expenditures for each year. The details of those expenditures are broadened to identify the cost for air, water, and land and other, as well as for the industry operating segments;

TABLE 5

STATUS OF IMCO-RELATED INTERNATIONAL CONVENTIONS

Convention	Date of U.S. Ratification	Date In Force Internationally
Safety of Life at Sea (SOLAS) 1960		1965
Amendments:		
1966 (Fire Safety)	04-07-67	
1967 (Fire Safety/Radio)	06-10-68	
1968 (Navigation/Equipment)	11-22-72	
1969 (Equipment, Surveys, and Radio)	11-22-72	
1971 (Radios and Routing)	11-16-73	
1973 (Editorial)	02-03-76	
1973 (Grain)	02-03-76	
Safety of Life at Sea (SOLAS), 1974	09-07-78	05-25-80
1978 Protocol (TSPP)	08-12-80	05-01-81
Collision Regulations, 1972	11-23-76	1977
Oil Pollution, 1954		1958
Amendments:		
1962 (Rewrite)	09-21-66	1967
1969 (Eliminate prohibited zones, allows limited discharge)	10-17-73	1978
1971 (Tanker tank size)		
1971 (Great Barrier Reef)		
International Pollution from Ships (MARPOL), 1973		
1978 Protocol (includes modified text of 1973 convention)	08-12-80	
Load Line, 1966	11-17-66	1968
1975 Amendments	08-12-80	
Tonnage Measurement, 1969		07-18-82
Intervention, 1969 (High Seas, Oil Pollution Casualties)	02-21-74	1975
Civil Liability, 1969		06-19-75
Compensation Fund, 1973		10-16-78
Safe Containers (Geneva, 1972)	01-03-78	09-06-77
Search and Rescue Convention, 1979	08-12-80	
Intervention, 1973 (High Seas, Other Than Oil)	09-07-78	
Ocean Dumping (London, 1972) non-IMCO	04-24-74	1975
Standards of Training, Certification, and Watchkeeping, 1978		

i.e., exploration and production, transportation, marketing, and refining. These costs include only firmly identified expenditures and do not include costs of delays or lost opportunities resulting from environmental regulations.

Specific details of the latest survey are provided in Tables 6, 7, 8, 9, and 10. Figures 6, 7, and 8 show some very interesting trends in expenditures, especially the dramatic increase in operating expenditures when compared with capital expenditures. This increase is due in part to the large increase in the cost of energy to operate the control equipment and the process units to make environmentally acceptable products, as well as the increased effort to operate and maintain the new pollution control devices. By 1979, the total expenditures for the 10-year period for capital and operating expenses were essentially the same, approximately $8.5 billion each. By 1980, the total 10-year operating expenditures exceeded the capital expenditures by almost $1.1 billion and that trend is predicted to continue.

The Future

During the 1970's, Battelle Columbus Laboratories analyzed the cost of environmental regulations to the U.S. domestic petroleum industry.[6] The 1980 study, conducted during the 1978-1979 period, not only included the cost of controlling pollution in production, refining, transportation, and marketing, but also added the cost of providing products that met the specifications set by environmental regulations.

The Battelle report estimates costs for the entire petroleum industry and presents its results in terms of constant 1979 dollars. These costs are different from the API-reported costs.

The analysis developed both capital and operating costs and from these developed an annualized cost using a 12.5 percent return after taxes. Two cost scenarios were developed—an anticipated case, which assumes moderate regulatory severity, and a restrictive case, which assumes a severe one. This report will use the anticipated case where regulations are in place or nearly so and the restrictive scenario only in the case of those regulations resulting from RCRA.

The cumulative capital investment by 1990 is $57 billion (constant 1979 dollars, excluding RCRA requirements) in the anticipated case. The annual capital cost for 1990 is $2 billion; of particular interest is the fact that the increased energy required in 1990 for the facilities represented by these expenditures is equivalent to approximately 450,000 barrels of oil per day.

The most costly potential regulations are those related to RCRA, which amount to an annualized cost of $44 billion in 1990 using a strict interpretation of regulations announced at the time of the study. Because of uncertainties in regulations to be proposed and legislation being considered at the time, it was impossible then as now to evaluate the impact properly. It is now anticipated that EPA's approach will be moderated to a large degree so that this is an exaggerated case in the short term.

Tables 11, 12, 13, and 14 summarize the various analyses made during the study for all industry sectors, again excluding RCRA costs. The petroleum industry as a whole was forecasted to incur an annualized cost of $13 billion in 1980 (1979 dollars), which will rise in 1990 to $17 billion plus RCRA costs. For additional details, see the Battelle report.

In order to put these expenditures and forecasted costs in some perspective, Table 15 shows the estimated incremental pollution expenditures for both the public and private sectors in the United States for the 1979-1988 period, as projected by the Council on Environmental Quality in 1980.[7] During the 10 years from 1979 to 1988, total spending in response to the federal environmental quality regulations is expected to total $518.5 billion.

TABLE 6

SUMMARY TABLE OF ENVIRONMENTAL EXPENDITURES OF THE PETROLEUM INDUSTRY, 1971-1980*
(Millions of Dollars)

	Year										Total
	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1971-1980
Total Expenditures (Table 7)											
Air	571	550	737	932	1,039	1,216	1,188	1,349	1,616	2,184	11,382
Water	415	379	402	530	629	822	950	884	1,001	1,299	7,311
Land and Other	101	91	100	150	456	336	383	194	203	357	2,371
Total	$1,087	$1,020	$1,239	$1,612	$2,124	$2,374	$2,521	$2,427	$2,820	$3,840	$21,064
Capital Expenditures (Table 8)											
Air	391	305	436	527	601	536	339	429	561	728	4,853
Water	224	184	194	271	356	411	434	340	394	527	3,335
Land and Other	57	51	52	97	396	269	184	89	92	183	1,470
Total	$672	$540	$682	$895	$1,353	$1,216	$957	$858	$1,047	$1,438	$9,658
Administrative, Operating, and Maintenance Expenditures (Table 9)											
Air	143	198	251	352	389	635	792	864	997	1,392	6,013
Water	185	187	201	249	262	401	502	532	594	754	3,867
Land and Other	41	37	43	50	55	63	197	101	106	165	858
Total	$369	$422	$495	$651	$706	$1,099	$1,491	$1,497	$1,697	$2,311	$10,738
Research and Development Expenditures (Table 10)											
Air	37	47	50	53	49	45	57	56	58	64	516
Water	6	8	7	10	11	10	14	12	13	18	109
Land and Other	3	3	5	3	5	4	2	4	5	9	43
Total	$46	$58	$62	$66	$65	$59	$73	$72	$76	$91	$668

*Data are shown as reported to API; they do not represent 100 percent of the expenditures.

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

TABLE 7

TOTAL ENVIRONMENTAL EXPENDITURES OF THE PETROLEUM INDUSTRY, 1971-1980*
(Millions of Dollars)

	Year										Total
	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1971-1980
AIR:											
Capital	391	305	436	527	601	536	339	429	561	728	4,853
Administrative, Operating, and Maintenance	143	198	251	352	389	635	792	864	997	1,392	6,013
Research & Development	37	47	50	53	49	45	57	56	58	64	516
Total	$571	$550	$737	$932	$1,039	$1,216	$1,188	$1,349	$1,616	$2,184	$11,382
WATER:											
Capital	224	184	194	271	356	411	434	340	394	527	3,335
Administrative, Operating, and Maintenance	185	187	201	249	262	401	502	532	594	754	3,867
Research & Development	6	8	7	10	11	10	14	12	13	18	109
Total	$415	$379	$402	$530	$629	$822	$950	$884	$1,001	$1,299	$7,311
LAND AND OTHER:											
Capital	57	51	52	97	396	269	184	89	92	183	1,470
Administrative, Operating, and Maintenance	41	37	43	50	55	63	197	101	106	165	858
Research & Development	3	3	5	3	5	4	2	4	5	9	43
Total	$101	$91	$100	$150	$456	$336	$383	$194	$203	$357	$2,371
AIR, WATER, LAND AND OTHER:											
Capital	672	540	682	895	1,353	1,216	957	858	1,047	1,438	9,658
Administrative, Operating, and Maintenance	369	422	495	651	706	1,099	1,491	1,497	1,697	2,311	10,738
Research & Development	46	58	62	66	65	59	73	72	76	91	668
Total	$1,087	$1,020	$1,239	$1,612	$2,124	$2,374	$2,521	$2,427	$2,820	$3,840	$21,064

*Data shown are as reported to API; they do not represent 100 percent of the expenditures.

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

TABLE 8

ENVIRONMENTAL CAPITAL EXPENDITURES OF THE PETROLEUM INDUSTRY, 1971-1980*
(Millions of Dollars)

	Year										Total
	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1971-1980
AIR:											
Exploration & Production	15	17	14	27	59	85	68	59	55	123	522
Transportation	8	3	10	22	37	30	26	20	15	33	204
Marketing	39	21	43	105	55	36	15	18	43	74	449
Manufacturing	329	264	369	373	450	385	230	332	448	498	3,678
Total	$391	$305	$436	$527	$601	$536	$339	$429	$561	$728	$4,853
WATER:											
Exploration & Production	82	68	62	92	117	135	187	206	240	316	1,505
Transportation	20	16	22	37	84	57	45	38	35	50	404
Marketing	10	14	17	19	25	16	13	13	19	38	184
Manufacturing	112	86	93	123	130	203	189	83	100	123	1,242
Total	$224	$184	$194	$271	$356	$411	$434	$340	$394	$527	$3,335
LAND AND OTHER:											
Exploration & Production	13	22	27	38	57	70	54	59	63	120	523
Transportation	6	8	9	37	322	188	106	18	12	14	720
Marketing	11	14	8	6	4	3	3	4	3	14	70
Manufacturing	27	7	8	16	13	8	21	8	14	35	157
Total	$57	$51	$52	$97	$396	$269	$184	$89	$92	$183	$1,470
AIR, WATER, LAND AND OTHER: Total	$672	$540	$682	$895	$1,353	$1,216	$957	$858	$1,047	$1,438	$9,658

*Data shown are as reported to API; they do not represent 100 percent of the expenditures.

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

TABLE 9

ENVIRONMENTAL ADMINISTRATIVE, OPERATING, AND MAINTENANCE EXPENDITURES OF THE PETROLEUM INDUSTRY, 1971-1980*
(Millions of Dollars)

	Year										Total
	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1971-1980
AIR:											
Exploration & Production	8	8	12	15	20	21	28	32	35	62	241
Transportation	6	3	4	3	7	16	11	12	12	16	90
Marketing	13	15	21	43	34	24	30	29	37	52	298
Manufacturing	116	172	214	291	328	574	723	791	913	1,262	5,384
Total	$143	$198	$251	$352	$389	$635	$792	$864	$997	$1,392	$6,013
WATER:											
Exploration & Production	84	66	69	90	87	115	141	154	173	215	1,194
Transportation	21	15	16	25	28	46	37	36	35	39	298
Marketing	5	6	7	8	11	13	13	22	19	24	128
Manufacturing	75	100	109	126	136	227	311	320	367	476	2,247
Total	$185	$187	$201	$249	$262	$401	$502	$532	$594	$754	$3,867
LAND AND OTHER:											
Exploration & Production	16	16	20	24	29	27	31	38	36	52	289
Transportation	5	9	8	8	8	14	128	24	18	19	241
Marketing	7	4	5	5	3	3	4	5	5	8	49
Manufacturing	13	8	10	13	15	19	34	34	47	86	279
Total	$41	$37	$43	$50	$55	$63	$197	$101	$106	$165	$858
AIR, WATER, LAND AND OTHER: Total	$369	$422	$495	$651	$706	$1,099	$1,491	$1,497	$1,697	$2,311	$10,738

*Data shown are as reported to API; they do not represent 100 percent of the expenditures.

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

TABLE 10

ENVIRONMENTAL RESEARCH AND DEVELOPMENT EXPENDITURES OF THE PETROLEUM INDUSTRY, 1971-1980*
(Millions of Dollars)

	Year										Total
	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1971-1980
AIR:											
Product	22	18	19	18	15	18	24	25	21	21	201
Process	14	26	29	33	32	25	30	28	34	40	291
Sampling and Testing	1	3	2	2	2	2	3	3	3	3	24
Total	$37	$47	$50	$53	$49	$45	$57	$56	$58	$64	$516
WATER:											
Product	2	2	1	2	3	2	4	4	3	4	27
Process	3	4	4	7	6	7	6	7	9	12	65
Sampling and Testing	1	2	2	1	2	1	4	1	1	2	17
Total	$6	$8	$7	$10	$11	$10	$14	$12	$13	$18	$109
LAND AND OTHER:											
Product	—	1	1	—	1	1	—	—	1	2	7
Process	1	1	2	2	2	2	2	3	3	5	23
Sampling and Testing	2	1	2	1	2	1	—	1	1	2	13
Total	$3	$3	$5	$3	$5	$4	$2	$4	$5	$9	$43
AIR, WATER, LAND AND OTHER: Total	$46	$58	$62	$66	$65	$59	$73	$72	$76	$91	$668

*Data shown are as reported to API; they do not represent 100 percent of the expenditures.

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

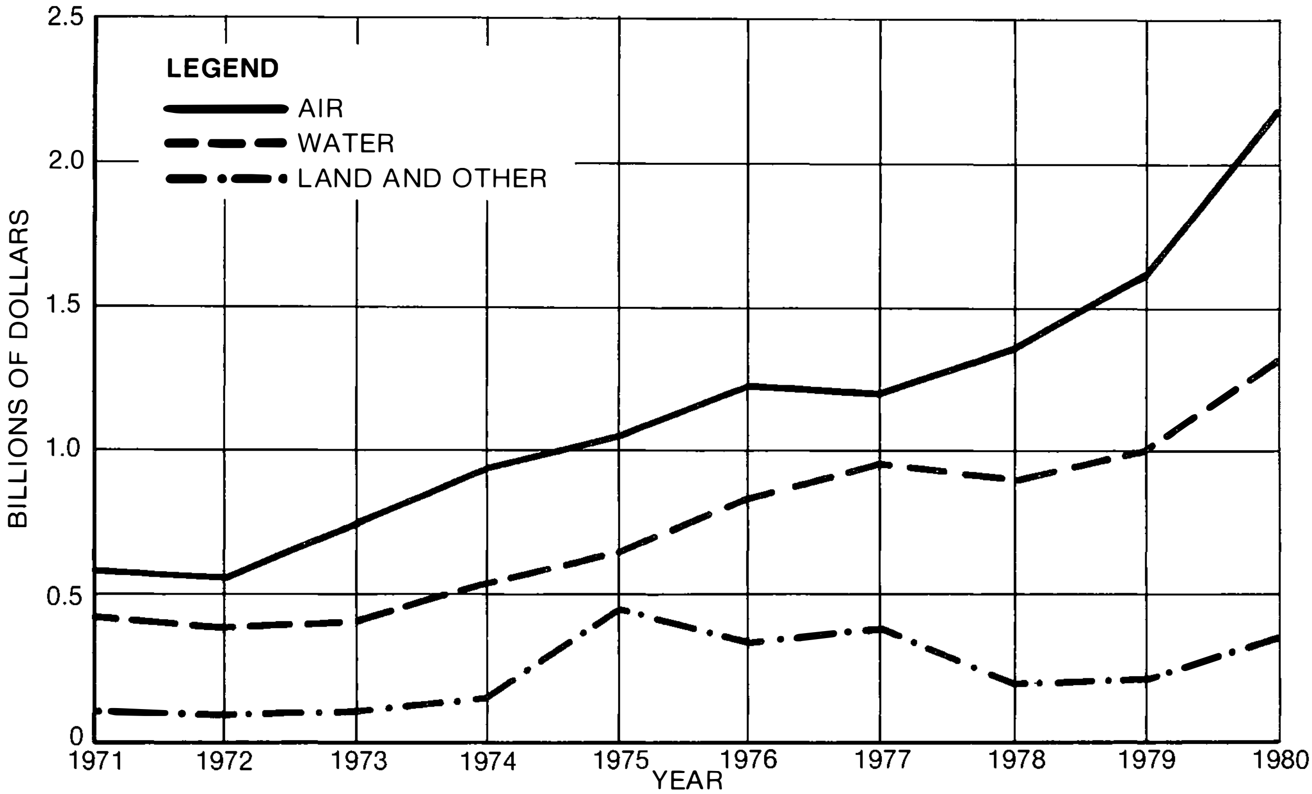


Figure 6. Total Environmental Expenditures of the Petroleum Industry.

NOTE: Data shown are as reported to API; they do not represent 100 percent of the expenditures.

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

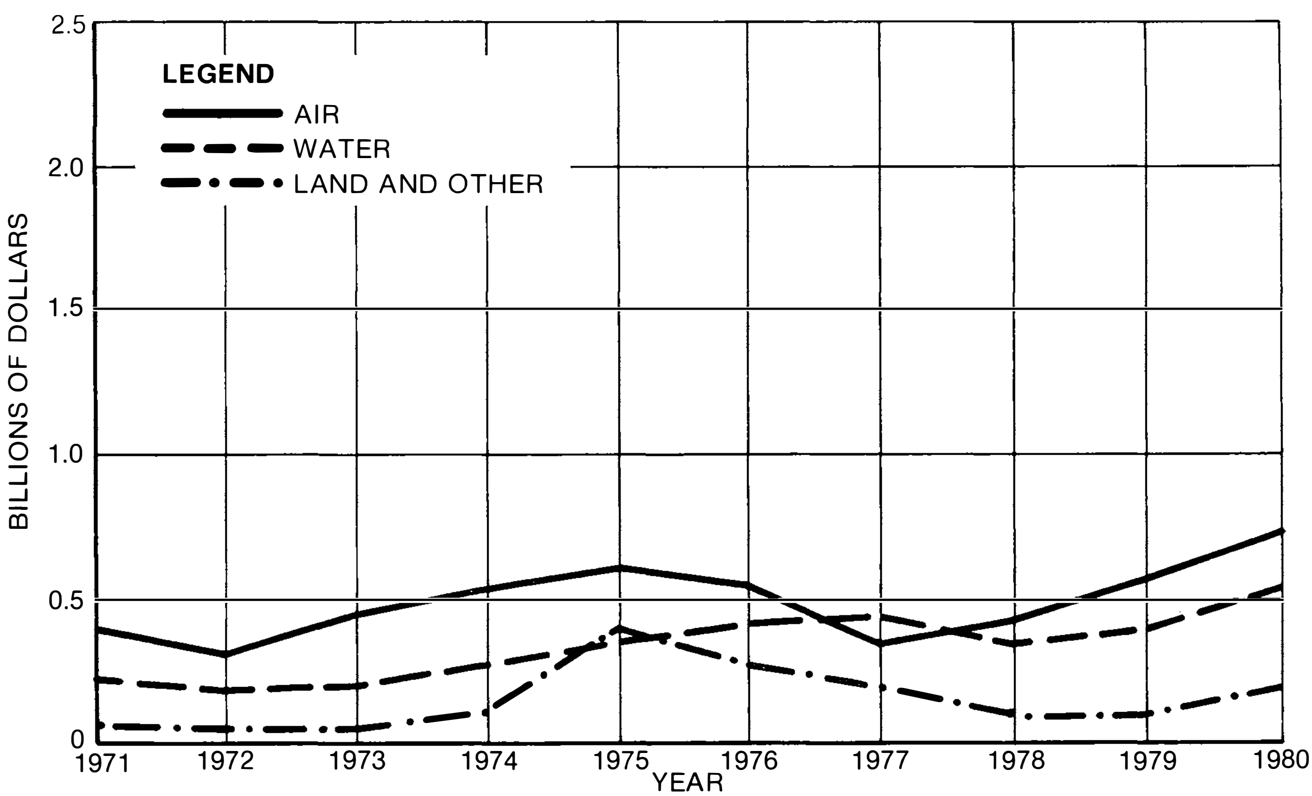


Figure 7. Environmental Capital Expenditures of the Petroleum Industry.

NOTE: Data shown are as reported to API; they do not represent 100 percent of the expenditures.

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

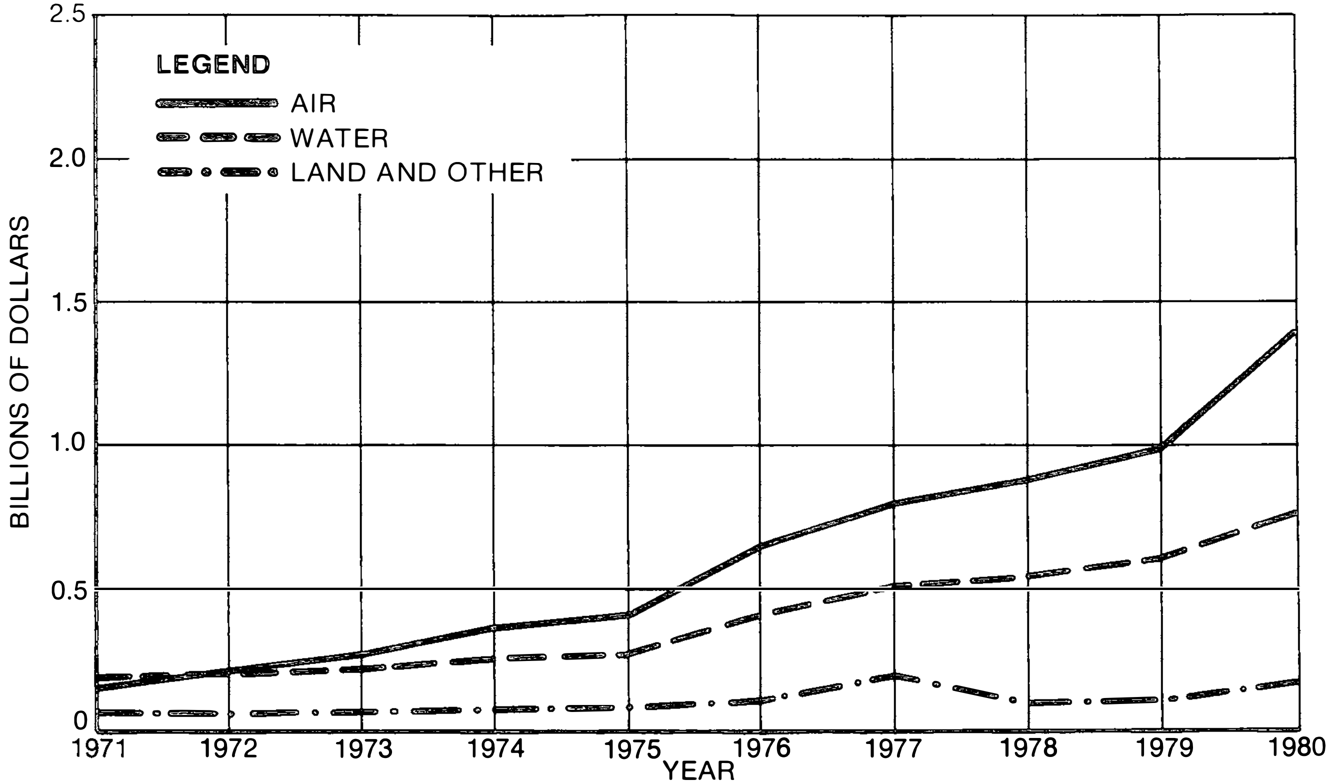


Figure 8. Environmental Administrative, Operating, and Maintenance Expenditures of the Petroleum Industry.

NOTE: Data shown are as reported to API; they do not represent 100 percent of the expenditures.

SOURCE: American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry*, 1981.

TABLE 11

TOTAL ANNUALIZED COSTS OF ENVIRONMENTAL REGULATIONS TO THE PETROLEUM INDUSTRY*

(Millions of 1979 Dollars)

	1970	1975	1980	1985 Anticipated	1990 Anticipated
Air					
Exploration and Production	26	88	320	600	850
Transportation	—	23	73	80	110
Refining	540	3,400	5,300	5,900	5,800
Distribution and Marketing	—	220	310	350	330
All Sectors	566	3,700	6,100	6,900	7,800
Water					
Exploration and Production	1,400	2,400	3,600	4,900	5,500
Transportation	3	42	120	410	440
Refining	290	1,000	1,900	2,100	2,200
Distribution and Marketing	—	48	180	180	180
All Sectors	1,700	3,500	5,800	7,600	8,300
Solid					
Exploration and Production	23	35	45	54	40
Transportation	—	—	—	—	—
Refining	—	—	—	—	—
Distribution and Marketing	—	—	—	—	—
All Sectors	23	35	45	54	40
Other Pollution (Odor, Noise, etc.)					
Exploration and Production	19	19	19	19	19
Transportation	1	65	82	82	81
Refining	2	50	320	810	830
Distribution and Marketing	—	—	—	—	—
All Sectors	22	130	420	910	930
All Pollution					
Exploration and Production	1,400	2,600	4,000	5,600	6,400
Transportation	4	130	270	570	630
Refining	830	4,400	7,500	8,800	8,800
Distribution and Marketing	—	270	490	530	500
All Sectors	2,300	7,400	12,000	15,000	16,000
Unallocated					
All Sectors	80	160	220	230	230
Grand Total	$2,400	$7,500	$13,000	$16,000	$17,000

*Excludes RCRA costs. Totals may not equal the sum of columns due to independent rounding.

SOURCE: Battelle Columbus Laboratories, *The Cost of Environmental Regulations to the Petroleum Industry*, July 31, 1980.

TABLE 12

CUMULATIVE CAPITAL INVESTMENT EXPENDITURES ON ENVIRONMENTAL REGULATIONS BY THE PETROLEUM INDUSTRY*
(Millions of 1979 Dollars)

	1970	1975	1980	1985 Anticipated	1990 Anticipated
Air					
Exploration and Production	76	270	820	1,400	2,000
Transportation	—	52	160	180	290
Refining	1,800	7,400	11,000	13,000	19,000
Distribution and Marketing	—	800	12,000	1,800	2,000
All Sectors	1,900	8,500	13,000	16,000	23,000
Water					
Exploration and Production	4,700	7,200	11,000	16,000	21,000
Transportation	7	110	310	1,300	1,500
Refining	850	2,600	4,800	5,900	7,500
Distribution and Marketing	—	210	540	540	540
All Sectors	5,600	10,000	16,000	24,000	30,000
Solid					
Exploration and Production	—	—	—	—	—
Transportation	—	—	—	—	—
Refining	—	—	—	—	—
Distribution and Marketing	—	—	—	—	—
All Sectors	—	—	—	—	—
Other Pollution (Odor, Noise, etc.)					
Exploration and Production	15	90	170	240	320
Transportation	6	260	330	330	330
Refining	1	180	1,200	2,900	3,000
Distribution and Marketing	—	—	—	—	—
All Sectors	22	530	1,600	3,500	3,700
All Pollution					
Exploration and Production	4,800	7,600	12,000	17,000	23,000
Transportation	13	420	790	1,900	2,100
Refining	2,700	10,000	17,000	22,000	30,000
Distribution and Marketing	—	1,000	1,700	2,300	2,600
Grand Total	$7,500	$19,000	$31,000	$43,000	$57,000

*Excludes RCRA costs. Totals may not equal the sum of columns due to independent rounding.

SOURCE: Battelle Columbus Laboratories, *The Cost of Environmental Regulations to the Petroleum Industry*, July 31, 1980.

TABLE 13

ANNUAL CAPITAL INVESTMENT ON ENVIRONMENTAL EXPENDITURES BY THE PETROLEUM INDUSTRY*
(Millions of 1979 Dollars)

	1970	1975	1980	1985 Anticipated	1990 Anticipated
Air					
Exploration and Production	19	78	160	120	120
Transportation	—	32	—	26	1
Refining	1,500	610	1,000	213	390
Distribution and Marketing	—	390	52	150	33
All Sectors	1,500	1,100	1,200	500	550
Water					
Exploration and Production	470	610	890	1,000	1,000
Transportation	7	44	13	205	22
Refining	170	480	130	200	410
Distribution and Marketing	—	3	—	—	140
All Sectors	640	1,100	1,000	1,400	1,400
Solid					
Exploration and Production	—	—	—	—	—
Transportation	—	—	—	—	—
Refining	—	—	—	—	—
Distribution and Marketing	—	—	—	—	—
All Sectors	—	—	—	—	—
Other Pollution (Odor, Noise, etc.)					
Exploration and Production	15	15	15	15	15
Transportation	6	68	—	—	—
Refining	1	170	170	12	18
Distribution and Marketing	—	—	—	—	—
All Sectors	22	250	180	27	33
All Pollution					
Exploration and Production	500	700	1,000	1,100	11,000
Transportation	13	140	13	230	23
Refining	1,700	1,300	1,300	430	820
Distribution and Marketing	—	390	52	150	33
Grand Total	$2,200	$2,500	$2,500	$1,900	$2,000

*Excludes RCRA costs. Totals may not equal the sum of columns due to independent rounding.

SOURCE: Battelle Columbus Laboratories, *The Cost of Environmental Regulations to the Petroleum Industry,* July 31, 1980.

TABLE 14

NET OPERATING COSTS OF ENVIRONMENTAL REGULATIONS BY THE PETROLEUM INDUSTRY*
(Millions of 1979 Dollars)

	1970	1975	1980	1985 Anticipated	1990 Anticipated
Air					
Exploration and Production	8	27	140	280	420
Transportation	—	11	38	39	43
Refining	110	1,600	2,800	3,100	3,000
Distribution and Marketing	—	40	39	-50	-81
All Sectors	120	1,700	3,000	3,400	3,300
Water					
Exploration and Production	320	830	1,200	1,400	1,400
Transportation	1	18	47	93	93
Refining	93	400	770	860	920
Distribution and Marketing	—	—	57	57	57
All Sectors	410	1,200	2,100	2,400	2,500
Solid					
Exploration and Production	23	35	45	54	40
Transportation	—	—	—	—	—
Refining	—	—	—	—	—
Distribution and Marketing	—	—	—	—	—
All Sectors	23	35	45	54	40
Other Pollution (Odor, Noise, etc.)					
Exploration and Production	—	—	—	—	—
Transportation	—	6	8	8	8
Refining	—	7	51	130	135
Distribution and Marketing	—	—	—	—	—
All Sectors	—	13	59	140	140
All Pollution					
Exploration and Production	350	900	1,400	1,700	190
Transportation	1	35	93	140	140
Refining	200	2,100	3,600	4,100	4,000
Distribution and Marketing	—	40	97	7	-26
All Sectors	500	3,000	5,200	6,000	6,000
Unallocated					
All Sectors	80	160	220	230	230
Grand Total	$630	$3,200	$5,400	$6,200	$6,200

*Excludes RCRA costs. Totals may not equal the sum of columns due to independent rounding.

SOURCE: Battelle Columbus Laboratories, *The Cost of Environmental Regulations to the Petroleum Industry*, July 31, 1980.

TABLE 15

ESTIMATED INCREMENTAL POLLUTION ABATEMENT EXPENDITURES—1979-1988*
(Billions of 1979 Dollars)

Program	1979			1988			Cumulative (1979-1988)		
	Operation and Mainte-nance	Annual Capital Costs†	Total Annual Costs	Operation and Mainte-nance	Annual Capital Costs†	Total Annual Costs	Operation and Mainte-nance	Capital Costs†	Total Costs
Air Pollution									
Public	1.2	0.3	1.5	2.0	0.5	2.5	15.8	3.7	19.5
Private									
Mobile	3.2	4.9	8.1	3.7	11.0	14.7	32.1	83.7	115.8
Industrial	2.0	2.3	4.3	3.0	4.1	7.1	25.8	33.0	58.8
Electric Utilities	5.5	2.9	8.4	7.6	5.7	13.3	62.3	42.7	105.0
Subtotal	11.9	10.4	22.3	16.3	21.3	37.6	136.0	163.1	299.1
Water Pollution									
Public	1.7	4.3	6.0	3.3	10.0	13.3	25.1	59.2	84.3
Private									
Industrial	3.4	2.6	6.0	5.4	4.5	9.9	42.0	34.0	76.0
Electric Utilities	0.3	0.4	0.7	0.3	0.9	1.2	2.9	6.5	9.4
Subtotal	5.4	7.3	12.7	9.0	15.4	24.4	70.0	99.7	169.7
Solid Waste									
Public	< 0.05	< 0.05	< 0.05	0.4	0.3	0.7	2.6	2.0	4.6
Private	< 0.05	< 0.05	< 0.05	0.9	0.7	1.6	6.4	4.4	10.8
Subtotal	< 0.05	< 0.05	< 0.05	1.3	1.0	2.3	9.0	6.4	15.4
Toxic Substances	0.1	0.2	0.3	0.5	0.6	1.1	3.6	4.6	8.2
Drinking Water	< 0.05	< 0.05	< 0.05	0.1	0.3	0.4	1.3	1.4	2.7
Noise	< 0.05	0.1	0.1	0.6	1.0	1.6	2.6	4.3	6.9
Pesticides	0.1	< 0.05	0.1	0.1	< 0.05	0.1	1.2	< 0.05	1.2
Land Reclamation	0.3	1.1	1.4	0.3	1.2	1.5	3.8	11.5	15.3
Total	$17.8	$19.1	$36.9	$28.2	$40.8	$69.0	$227.5	$291.0	$518.5

*Incremental costs are those made in response to federal legislation beyond those that would have been made in the absence of that legislation.
†Interest and depreciation.

SOURCE: Council on Environmental Quality, *Environmental Quality*, 1980.

References and Notes

[1] Environmental Research and Technology, Inc., *Effects of the Clean Air Act on Industrial Planning and Development*, July 1981; Environmental Research and Technology, Inc., *Impact of Air Quality Permits Procedures on Industrial Planning and Development*, November 1980; National Council on Air Quality, *To Breathe Clean Air, Report to the Congress*, March 1981.

[2] *Federal Register*, 45 FR 52696.

[3] SCS Engineers, *Assessment of Petroleum Industry Cost of Compliance With Proposed Hazardous Waste Regulations*, 1979.

[4] These features are stated as optional annexes to the Convention; i.e., a state could adopt the Convention with or without any of these features.

[5] American Petroleum Institute, *Environmental Expenditures of the United States Petroleum Industry, 1971-1980*, 1981.

[6] Battelle Columbus Laboratories, *The Cost of Environmental Regulations to the Petroleum Industry*, July 31, 1981.

[7] Council on Environmental Quality, *Environmental Quality—1980*, December 1980.

Chapter Two
Petroleum Industry Operations and the Environment

Introduction

In updating its 1971 report, *Environmental Conservation—The Oil and Gas Industries*, the Council reviewed the progress made by the petroleum industry over the last decade in meeting the public needs for both energy and environmental quality. The following discussions examine the operations and particular environmental considerations of each of the major segments of the petroleum industry: exploration and production; refining; and storage, transportation, and marketing. In addition, the issues of petroleum product use, the fate and effects of spills of oil and hazardous substances, and energy facility siting are briefly examined. These discussions are presented in more detail in a report expected to be published by the Council in mid-1982.

Exploration and Production

Industry Operations

The many facets of oil and gas exploration and production operations are interrelated and interdependent, functioning concurrently for most of the life of a producing area. These operations occur in many environments, from desert to frozen tundra, onshore and offshore. While geographic and weather extremes can require some unique operating practices, most exploration and production operations follow the methods described below and illustrated in Figure 9.

Exploration begins with geological and geophysical work and continues through the drilling and evaluation of one or more wells, only 10 percent of which are productive on average. Evaluation usually does not stop with the completion of a discovery well. Confirmation and extension wells are necessary to determine if the reservoir is of commercial quality and size. After a sufficient volume of producible oil and/or gas has been confirmed, production facilities are installed, development wells drilled, transportation to refineries arranged, and production initiated.

During the productive life of a field, it is usually necessary to re-enter producing wells to do repairs and modifications, such as production stimulation, control of produced waters, and control of formation sand incursion. When the natural reservoir pressure of an oil reservoir declines and an oil well no longer flows, artificial lift devices (pumps) are usually installed. For gas wells, compressors are frequently installed to increase the rate of gas production and thus the producing life of the reservoir.

Gas produced with oil, or from gas wells, may contain sufficient heavy hydrocarbons to justify the installation of processing equipment for extraction of the natural gas liquids. Contaminants such as carbon dioxide and hydrogen sulfide must be removed from natural gas prior to transportation to markets.

The productive life of many oil fields is extended by water flood or gas injection (secondary recovery). In addition, some oil reservoirs can be revived by injection of steam, carbon dioxide, or chemicals (tertiary recovery).

As producing wells become uneconomic, they must be plugged with cement, salvageable casing pulled, surface equipment removed, and the surface area restored in a manner that will comply with the terms of the lease and the requirements of the regulatory agencies.

The length of time from the start of exploration until full production may be from five to ten years, while the productive life of a field can be 25 to 50 years, or longer. As the primary terms of leases become shorter and more small reservoirs are placed in production, these time estimates will decrease.

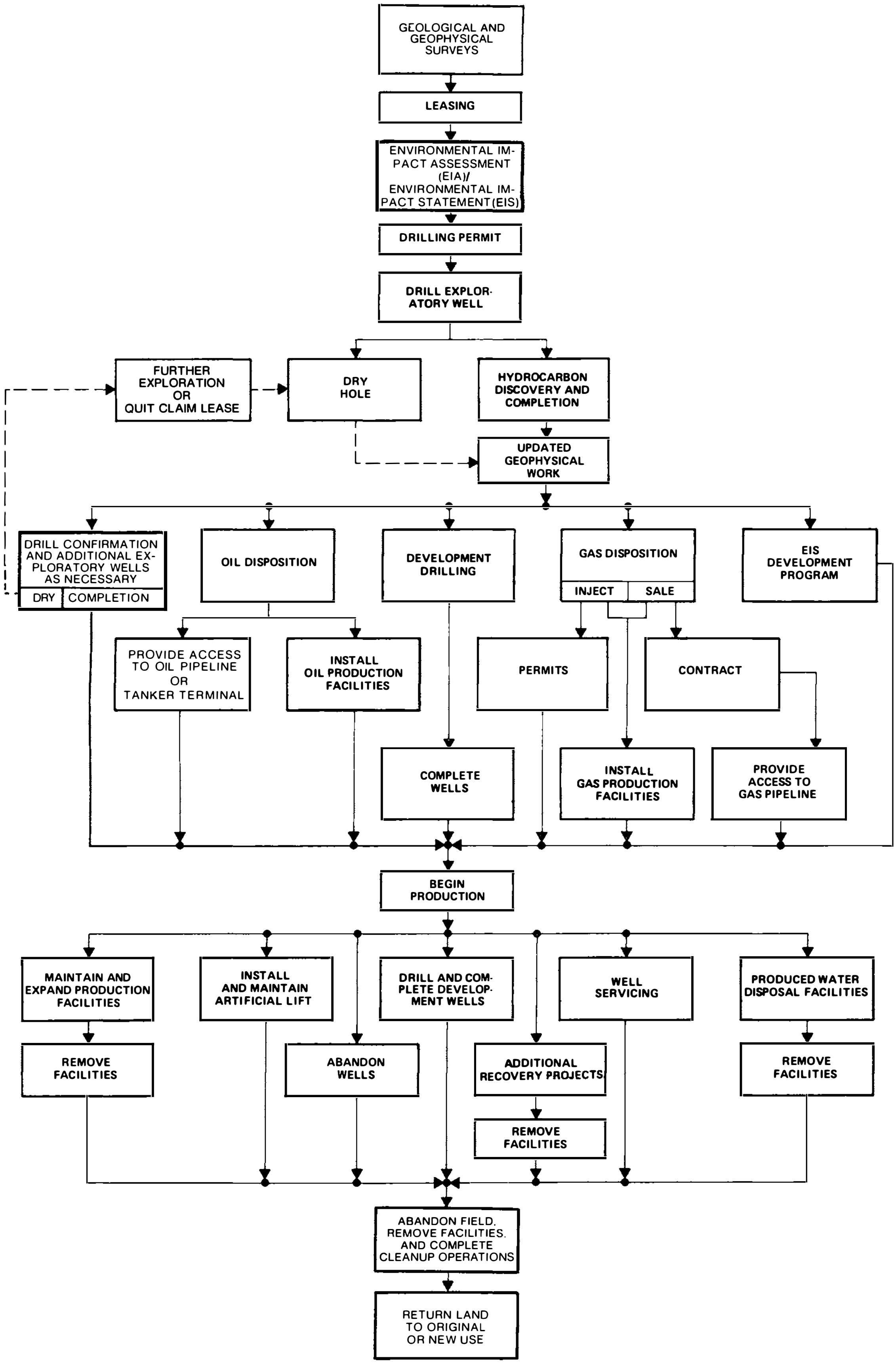


Figure 9. Simplified Flow Diagram Showing Operations for Exploration, Discovery, Production, and Abandonment of an Oil or Gas Field.

U.S. Resource Base

In order to place the domestic potential oil and gas recovery into perspective, the following resource base estimates are presented. These estimates are representative of the many objective and impartial assessments that have been made in recent years; inclusion in this section does not denote NPC endorsement.

Conventionally Producible Oil and Gas

The U.S. Geological Survey (USGS) February 1981 estimates of undiscovered recoverable oil and gas resources are presented on Table 16. Access to much of the offshore oil and gas potential is controlled by the federal government, while onshore, access to potential resource development areas is determined by federal, state, local, and Indian governments, and private land owners.

The NPC independently conducted an assessment of recoverable oil and gas resources for all areas under U.S. jurisdiction north of the Aleutian Islands offshore, and north of the Brooks Range onshore. The Council estimates the volume of undiscovered potentially recoverable hydrocarbons on the North Slope of Alaska to be 12.8 billion barrels of oil equivalent (BBOE), and from the Bering, Beaufort, and Chukchi regions offshore to be 30.8 BBOE. While these estimates are not strictly comparable (e.g., the USGS excludes natural gas liquids and in some instances the USGS and NPC considered different minimum field sizes), there is general agreement between the NPC and the USGS on total Arctic potential. Details of the NPC's assessment are published in its 1981 report, *U.S. Arctic Oil and Gas*, and are summarized in Appendix E of this report.

Tight Gas Reservoir Potential

In 1980, the NPC completed an assessment of potential resources of and recovery from tight gas reservoirs. These reservoirs are defined as blanket or lenticular natural gas formations that have an in situ effective permeability of less than 1 millidarcy. The results indicate that a range of between 192 trillion cubic feet (TCF) and 574 TCF of tight gas are recoverable, depending upon price and technology.[1]

Enhanced Oil Recovery Potential

In 1978 the Office of Technology Assessment undertook an assessment of potential oil recovery through enhanced techniques—any method used to recover oil from a petroleum

TABLE 16

USGS 1981 Estimates of Undiscovered Recoverable Oil and Gas Resources

Region	Crude Oil (billion barrels) Low F_{95}*	Crude Oil Mean†	Crude Oil High F_{95}*	Total Natural Gas (trillion cubic feet) Low F_5	Total Natural Gas Mean†	Total Natural Gas High F_5
Lower 48—Onshore	36.1	47.7	62.0	288.6	390.3	525.9
Lower 48—Offshore	8.7	15.8	25.1	66.1	102.4	148.2
Alaska—Onshore	2.5	6.9	14.6	19.8	36.6	62.3
Alaska—Offshore§ (Shelf and Slope)	4.6	12.3	24.2	33.3	64.6	109.6
Total United States	64.3	82.6	105.1	474.6	593.9	739.3

*F_{95} denotes the 95th fractile; the probability of *more than* the amount F_{95} is 95 percent. F_5 is defined similarly.
†Mean values may not be precisely additive due to rounding.
§Includes quantities considered recoverable *only* if technology permits their exploration beneath Arctic pack ice—a condition not yet met.

SOURCE: U.S. Geological Survey, *Estimates of Undiscovered Recoverable Resources of Conventionally Producible Oil and Gas in the United States, A Summary*, February 1981.

reservoir over and above what would be obtained by conventional, primary recovery techniques. The Office of Technology Assessment estimated that 49.2 billion barrels of heavy oil could be recoverable at a market price of $30 per barrel. [2]

Environmental Considerations

The major environmental issue confronting oil and gas exploration and development in the 1980's concerns adequate access to government lands. In order to develop the nation's oil and gas resources, the industry must first be allowed access to the land to determine the extent of the resources and, if they are economic, be permitted access to develop those resources in an environmentally acceptable manner. The following discussion describes the land use, access, and permitting issues and the exploration and production segments' air, water, and waste management considerations.

Land Use—Onshore

The federal government owns over one-third of the nation's onshore lands—about 728 million of the 2.3 billion acres in the United States (see Figure 10). In addition, the federal government retains mineral rights to over 60 million acres of state and private land.[3] The agencies' responsibility for managing and administering these lands are shown in Table 17. The principal authority rests with the Department of the Interior's Bureau of Land Management (BLM) and the Department of Agriculture's Forest Service.

Federal Land Policy and Management Act of 1976. The Federal Land Policy and Management Act of 1976 (FLPMA) established a comprehensive plan for the management of government lands under the jurisdiction of BLM. Over the years, the BLM's authority had been based on hundreds of government land laws, many of which had become obsolete.

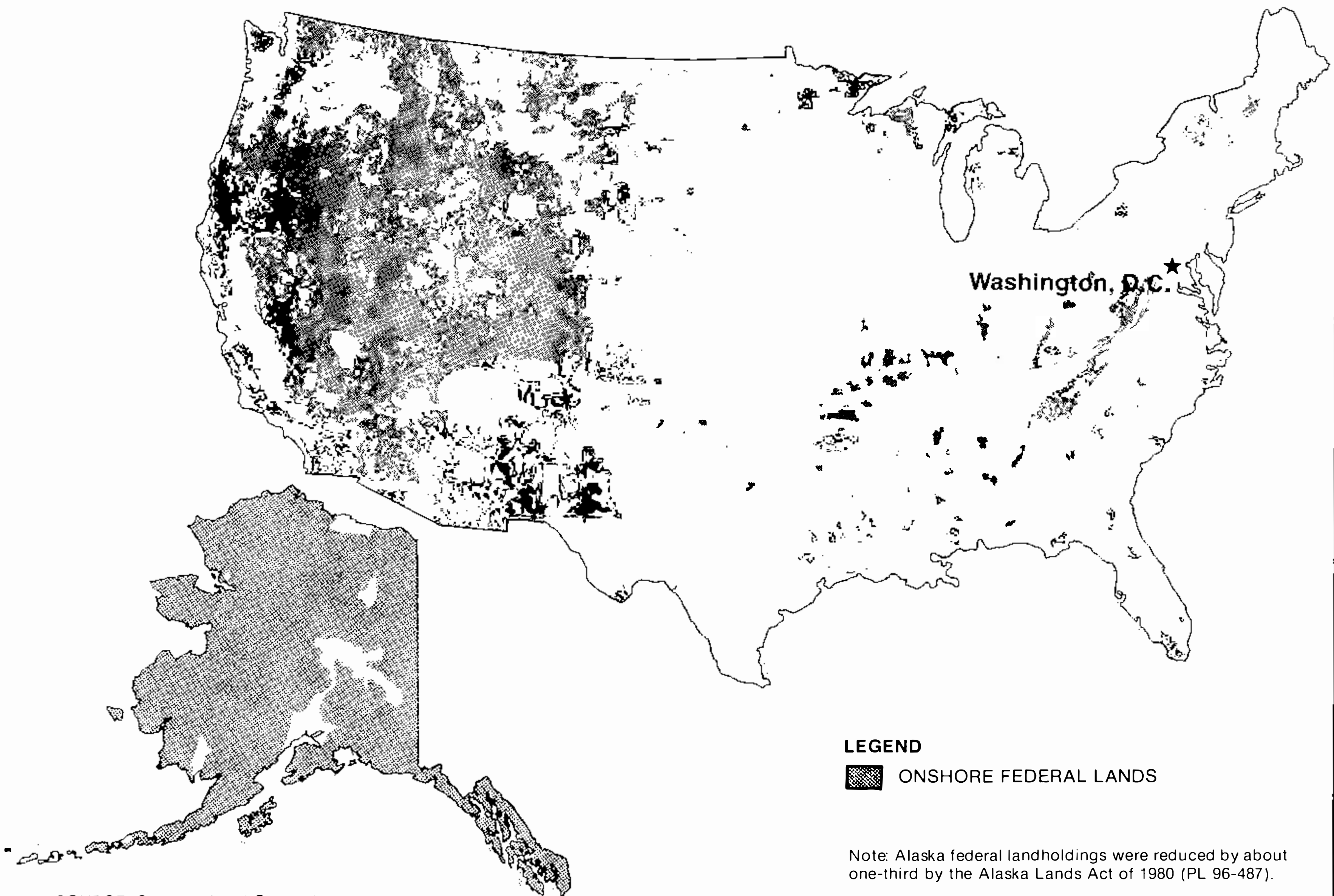
Congress identified a number of policy objectives in FLPMA:

- Sound management of government lands should involve the land-use planning process. As an essential part of the land-use planning process, FLPMA requires the BLM to "prepare and maintain . . . an inventory of all public lands and their resource and other values."

  Closely related to the general inventory is the special inventory required as a part of the BLM Wilderness Study. Under these provisions, the BLM is to undertake a special review of government lands in roadless areas of 5,000 acres or more. The Wilderness Study is to be completed by 1991 and is intended to identify areas that might be included in the National Wilderness Preservation System (NWPS) established under the Wilderness Act. As of November 18, 1981, the BLM had inventoried all 173.7 million acres of roadless areas under its jurisdiction. Over 149 million acres were determined to lack wilderness characteristics, and 24.3 million acres were determined to have wilderness characteristics.[4] Those areas not designated for wilderness will be managed under land-use plans in accordance with FLPMA's land-use planning process.
- In general, government lands should be managed on the basis of sustained yield and multiple use, with special recognition of the nation's need for domestic sources of minerals, food, timber, and fiber.
- Management for certain purposes may necessitate withdrawal. As an exception to the general principle of sustained yield-multiple use management, certain lands may be withdrawn. For areas of less than 5,000 acres, the Secretary of the Interior has the discretion to withdraw lands for specific periods of time. For areas of 5,000 acres or more, the Secretary may recommend withdrawal for a period of up to 20 years, subject to Congressional approval. FLPMA also provides that, if an emergency exists, Congress or the Secretary can immediately withdraw lands, but for no longer than three years.
- Areas of critical environmental concern (ACEC) deserved prompt protection. The BLM program administering ACEC seeks to protect environmental characteristics in areas where uncontrolled development could harm fragile ecosystems or cultural, historical, or scenic resources. To date, definitions are loose and guidelines offer little insight as to what BLM lands qualify as ACEC.

The Wilderness Act. The Wilderness Act of 1964 established a 15-million-acre system of wilderness areas. Under this and other acts total acreage of wilderness areas has since increased to 80 million acres, a more than five-fold increase.

While the Act itself provides that these lands are open to oil and gas exploration activities until December 31, 1983, very few oil and gas leases have been issued in wilderness areas. The wilderness designation is the most exclusionary single-use designation that can be applied to government lands. Motorized



Note: Alaska federal landholdings were reduced by about one-third by the Alaska Lands Act of 1980 (PL 96-487).

SOURCE: Congressional Quarterly, Inc., from U.S. Geological Survey, April 1978.

Figure 9. Federal Lands.

TABLE 17
ACRES OF LAND MANAGED BY FEDERAL AGENCIES*

Agency	Million Acres as of June 1, 1981	Percentage of Total U.S. Onshore Land
Department of the Interior		
Bureau of Land Management	338.0	16.9
Fish and Wildlife Service	85.0	4.5
National Park Service	70.6	3.5
Department of Agriculture		
Forest Service	190.0	9.5
Department of Defense	35.0	1.7
Remaining Agencies	10.0	0.5
Total	727.6	36.4

*Source of data: Environmental Policy Center et al., *Minerals and the Public Lands,* 1981. Totals may not add due to rounding.

vehicles, roads, and permanent campsites are prohibited in wilderness areas; travel in these areas can only be on foot, on horseback, or by canoe. Thus, unlike national parks, relatively few persons enter wilderness areas.

In addition to the 79.8 million acres now designated as wilderness within the NWPS (including 56.2 million acres in Alaska), as many as 9.9 million acres could be added under the Forest Service's second Roadless Area Review and Evaluation (RARE II) program.[5] Another 7.6 million acres of forest lands, known as future planning areas, and 23.7 million acres of BLM Wilderness Study Areas could be added to the NWPS. Thus, through these reviews alone, the wilderness system could be larger than 120 million acres, more than 16 percent of all government onshore lands.[6]

In past years, oil companies have been reluctant to attempt to explore on wilderness lands when other prospective acreage, not subject to restrictions under the Wilderness Act, was more readily accessible. But the need to increase domestic energy production and reduce dependence on foreign oil has provided an urgency to explore for oil and gas on wilderness lands. Oil and gas operations are compatible with wilderness areas; it has been demonstrated repeatedly that oil facilities can operate safely with only temporary and minimal disturbance to the environment.

Land Access and Land Withdrawals. Historically, government actions promoted access to government land for settlement and resource development. Historical and statutory precedent notwithstanding, certain Congressional and Executive Branch actions have served to restrict such access.

Taking a variety of forms and having varying procedures, withdrawals of government land from the operation of the general land laws can be achieved in several ways. Withdrawal from mineral entry and leasing may be made by filing applications for withdrawals, land selection, reservation, classification, or other actions that restrict access.

It is impossible to determine how much land is presently withdrawn, due to the number of ways in which land has been withdrawn, restricted, or made unavailable to mineral entry or leasing. The difficulty is compounded by the absence of accurate records within the federal agencies and by failures to act on applications for permits for use, which becomes a withdrawal in fact.

In 1981, the General Accounting Office (GAO) published a review of withdrawals of government lands from oil and gas leasing in five states.[7] Of the more than 6 million acres of administratively withdrawn land, the GAO found almost 55 percent of the land studied in those five states to have oil and gas potential

under the USGS criteria applied to the evaluation. In addition, the GAO found over 14 million acres formally withdrawn, 55 percent of which had oil and gas potential. The GAO estimated that 64.1 million acres of government lands were closed to federal leasing as of 1979, and as of February 1980, there were withdrawal applications pending on an additional 4.3 million acres of BLM land. The GAO also examined the total amount of government land that the USGS considered to be prospectively valuable for oil and gas for each of 40 states (excluding Alaska). Its analysis showed that 261 million acres of the total of 404 million acres of federal land met its criteria of "prospectively valuable."

According to Department of the Interior figures, to date the BLM has initiated withdrawal review with respect to approximately 67.9 million acres of land. Many of these withdrawals are for nonconservation reasons, e.g., Department of Defense facilities. About 18.9 million of those acres are segregated from mineral leasing. The Department of the Interior has stated that its first priority is to complete withdrawal review of approximately 29 withdrawals located in the Overthrust Belt in Idaho, Montana, Utah, Nevada, and Arizona.[8]

Forest Service and BLM Planning Programs. By statute, land management plans must be written and updated for all Forest Service or BLM lands. The emphasis is on surface management and, theoretically, a plan should anticipate all potential land uses. If conflicts exist, the plan should designate the preferred alternative. Any surface-disturbing activity not anticipated in a land-use plan is not permitted until and unless the plan is revised.

In general, land-use plans developed to date inadequately address oil and gas exploration and development. The NPC is concerned that the management processes, in their present state as reflected in those plans, could perpetuate a climate of uncertainty and restriction regarding petroleum, especially since the quantification of subsurface resources is imprecise when compared with the ready identification and quantification of surface resources.

Three topic areas will highlight this concern: definition, data adequacy, and attitude.

- *Definition.* Planners are not agreed on a definition of multiple use. Whether that term means co-existence or partitioned exclusivity is unclear. The issue is critical, because the statutory language mandating multiple use has been interpreted differently. Forest Service language derives from the 1960 Multiple-Use and Sustained-Yield Act and also implements provisions of the 1974 Forest Range Land Renewable Resources Planning Act, amended by the 1976 National Forest Management Act. The thrust of these acts has been to establish a sustained yield of forest products and services towards target goals. The effect has been to set forth a restricted definition of multiple use, as it is limited to surface use only and does not take into account subsurface resource goals. The definition in FLPMA is somewhat more broad, calling for resource utilization in the combination that will best meet the present and future needs.
- *Data Adequacy.* Data on petroleum potential are generous in highly drilled areas but meager or non-existent in undrilled areas. Data overload from other resources, competing with a dearth of petroleum-related data in undrilled areas, leads to increased attention to those resources for which the plentiful data assures sound footing in planning decisions. The absence of data may also cause planners to make incorrect conclusions as to the presence or absence of petroleum potential. Concurrently, Congressional policy dictates multiple use of the lands, including oil, gas, and other minerals. The use of the present planning process, dependent as it is on data adequacy, tends to thwart this Congressional policy.
- *Attitude.* Planners are inclined to regard petroleum operations as more damaging to the environment than has been demonstrated. There is a tendency to prepare for the worst possible case, ignoring countless examples of trouble-free oil and gas operational co-existence with other resource values. Some examples are the Aransas National Wildlife Refuge, a protected whooping crane nesting ground in the midst of an operating oil field; the caribou movement under and over the Trans-Alaskan Pipeline System; and offshore production platforms that have become marine sanctuaries in themselves.

Leasing, Bidding, and Lease Stipulations. Congressional actions over approximately the past 15 years and Executive Branch actions have placed severe restrictions on the multiple uses of federally controlled lands. Because the vast majority of wilderness areas, as mandated by Congress and through RARE I and II and the present BLM Wilderness Study Areas, are located on either BLM or Forest Service managed lands, lease issuance, primarily noncompetitive, has become of great concern to

the oil and gas industries operating in those areas. With the increased significance of the Overthrust Belt, which lies along the general Rocky Mountain front from Canada virtually to Mexico, time delays in lease issuance have become a major problem. Some applications on lands managed by the Forest Service and lying within RARE II areas have been filed for up to seven years without being issued.

Land management policies currently in effect are a fundamental factor in leasing rates and activities. These policies determine the ability of a company to find and develop energy resources. It is uncertainty, delay, and cumulative restrictions that make leasing on federal acreage less economic when compared to state or fee lands. This is especially true for small operators, who are least able to cope with these factors.

In addition, leases in environmentally sensitive areas often include "no-surface occupancy" stipulations, making surface access to the leasehold impossible. In essence, then, the relationship is one where the government on the one hand requires payment on lease rentals, while on the other it prohibits access and contractual lease rights.

In an effort to streamline the federal leasing and bidding processes, there must be a unification and consolidation of the federal regulatory administration as it relates to onshore leasing. It is most important to petroleum exploration and production that the entire process be simplified.

On the state level, each state has its own formula for developing and using lease stipulations. As with federal leases, state lease stipulations derive their authority primarily from state environmental protection laws, and leases must comply with all the requirements and rules of the state lands department.

Stipulations on Indian oil and gas agreements vary among tribes and among individual owners. When negotiating an oil and gas contract, an Indian tribe may include stipulations regarding the employment and training of tribal members, profit sharing, accounting, environmental protection, and other matters. Oil and gas agreements on Indian lands require compliance with any applicable tribal ordinances or regulations.

Onshore Permitting. The result of the enactment of FLPMA and NEPA and subsequent regulation on oil and gas development has been profound. Operating requirements have increased along with regard for the nature and extent of information required for submittal in plans, steps involved in the permit process, temporal and spatial restrictions, requirements for ancillary permits, and general conformance to operational standards, procedures, and environmental protection requirements. While a majority of the operational changes are warranted and have resulted in tangible benefits to the environment, the manner of implementation has caused delays in the permitting of oil and gas activities on federal lands.

The Notice of Lessees and Operator No. 6 Approval of Operations (NTL-6) is a permit program designed by the USGS to comply with NEPA requirements. Its objective is to assure that operations on oil and gas leases under USGS jurisdiction are conducted with due regard for environmental protection as well as to evaluate the environmental impacts of proposed operations via the required EIS process. Because of the number of discrete steps associated with the NTL-6 permit process, as well as the various agencies and individuals involved, multiple delay factors frequently are experienced by operators seeking approval of applications. The length of time to secure approval of an application for a permit to drill has increased from an estimated 15 days in 1976, prior to NTL-6 and FLPMA, to a general range of 80 to 100 days in 1980.

Land Use—Offshore

Outer Continental Shelf Lands Act Amendments of 1978 (OCSLAA). The original Outer Continental Shelf Lands Act of 1953 was a brief, clearly written bill focusing on the orderly development of OCS resources. It authorized the Secretary of the Interior to develop the rules and regulations necessary to prevent waste, conserve natural resources, and protect correlative government and lessee rights on the federal OCS. The bill also permitted geological and geophysical activity and directed that leases were to be issued "to meet the urgent need for further exploration and development of the submerged lands" of the OCS. The first oil and gas federal OCS lease sale was held in 1954. Since then, 54 other sales have been held. About 20 million acres have been leased and approximately 5,400 wells were producing on the OCS in 1980.[9]

After the passage of the 1953 Act, a number of bills were passed that have hindered operations on the federal OCS. Among these are NEPA (1970); Marine Protection, Research, and Sanctuaries Act of 1972; Coastal Zone Management Act of 1976; Clean Air Act, as amended in 1977; Federal Water

Pollution Control Act (Clean Water Act), as amended in 1977 and 1978; Marine Mammal Protection Act of 1972; the Endangered Species Act Amendments of 1978; and the OCSLAA (1978). Each of these has added to the regulatory burden and restrictions on OCS operations and their cumulative effect has seriously impeded the development of oil and gas resources on the federal OCS.

The OCSLAA, particularly, have delayed and restricted OCS operations, although that was not the intent of Congress. They were intended to clear the way for accelerated oil and gas leasing and development of the federal OCS. The amendments:

- Increased the number of agencies authorized to regulate certain OCS activities
- Required the Secretary of the Interior to consider state CZM plans in developing five-year lease schedules
- Provided for greater coastal state participation in the leasing decision process
- Mandated certain environmental impact studies
- Provided for citizen suits
- Compelled the use of alternative bidding systems
- Required the promulgation and implementation of some 40 new or revised regulations on offshore exploration and production operations.

Permitting and licensing of OCS activities have become much more complicated and, therefore, more time-consuming and expensive. The time required for the processing of exploration plans and development plans has increased to an average of 119 days and 206 days in 1980, respectively, as compared to 30 days for either type of plan prior to 1978.[10] Moreover, states, local governments, and private groups have repeatedly used court challenges to delay and sometimes force the withdrawal of lease sales.

Coastal Zone Management Act of 1976 (CZMA). The CZMA has the effect of providing coastal states with virtual veto power over federally licensed or permitted activities on the OCS. The veto applies if, in the opinion of the coastal state, federally approved activities will not be carried out in a manner consistent with the federally approved CZM program in that state. The CZMA and its regulations enable coastal states with approved CZM plans to delay and, in some instances, to prohibit the issuance of federal licenses and permits, including those needed under OCS oil exploration and production plans. The result may be lengthy delays in the energy search offshore.

Under the CZMA, a state with an approved CZM program can prevent the issuance of federal licenses and permits, including those needed under OCS plans, for as long as six months, simply by not acting on the applicant's consistency certification. If a state rejects the consistency certification, the license or permit in question cannot be issued unless the Secretary of Commerce overrides the state's action on his own initiative or on appeal by the applicant. The grounds on which the Secretary can override a state consistency decision are extremely narrow. Since there is no time limit within which he must act, a final decision can be delayed indefinitely.

Special provisions of the CZMA link federal consistency with oil and natural gas exploration and production plans. However, some states (notably California) have asserted that such activities as OCS tract selection, lease stipulations, and lease sales are federal activities "directly affecting" the coastal zone and therefore fall within the coverage of the federal consistency requirements.

In effect, these coastal states contend that the Secretary of the Interior must agree to all OCS tract selection and lease stipulations recommended by them. The Secretary of the Interior maintains that prelease OCS activities do not directly affect the coastal zone; this issue is currently under court review.

Coupled with the CZMA's limited grounds for overriding state nonconcurrence, the federal consistency provisions give the states considerable leverage over what was once exclusively federal decision-making. This leverage can amount to an effective veto and cause extensive delay.

Marine Sanctuaries Program. The Marine Sanctuaries Program stems from Title III of the Marine Protection, Research, and Sanctuaries Act of 1972. In the late 1960's and early 1970's, a number of other laws, including the CZMA, were passed to manage and protect air and water quality, marine mammals, estuaries, and endangered species, as well as to preserve archaeological and historical values. These laws offer substantial protection for ocean areas and marine life.

The Sanctuaries Program is administered by the National Oceanic and Atmospheric Administration (NOAA), and the Secretary of Commerce is empowered to designate as sanctuaries areas of the ocean "which he determines necessary for the purpose of preserving or restoring such areas for their conservation, recreational, ecological, or esthetic values." Under the original Act, a

marine sanctuary designation required the approval of the President and became effective only if affected states did not object within a 60-day period. As amended in 1980, the Act now also provides that Congress has a period within which to register its objection. For a designated marine sanctuary, the Secretary is authorized to issue "necessary and reasonable regulations to control any activities within the designated marine sanctuary."

Two areas proposed as sanctuaries have high energy potential: the Flower Gardens Banks (276 square miles around 14 miles of coral reefs) in the Gulf of Mexico, and the Santa Barbara Channel Islands (1,252 square miles above known oil and gas reserves). On September 21, 1980, NOAA designated the Santa Barbara Channel Islands Marine Sanctuary. Regulations associated with this designation could have prohibited all future oil and gas operations on unsold lease tracts in that area. However, in this case NOAA suspended the oil and gas prohibition until a regulatory analysis could be prepared.

Other areas with potentially large amounts of oil and gas, including vast areas of offshore Alaska (200,000 square miles) and Georges Bank, have been or may be proposed as sanctuaries. If these vast stretches of ocean are designated as marine sanctuaries, drilling for oil and gas could be restricted or precluded in portions or the entire area.

Offshore Leasing, Bidding, and Permitting. The Five-Year OCS Oil and Gas Leasing Schedule is of critical importance to the nation's commitment to increase domestic energy supply and is a vital planning tool for both government and industry in OCS exploration and development. The interests of the nation will be best served by an aggressive and predictable schedule; however, many potential impediments exist, which, if uncorrected, can thwart this objective. Impediments to expeditious OCS exploration and development arise from various administrative steps and procedures for each lease sale. Much of the delay resulting from these processes is correctable by administrative action.

The predicted environmental and socioeconomic impacts resulting from OCS sales in frontier areas are limited to impacts resulting from exploratory drilling. Since development and production activities will occur only where commercial discoveries of oil or gas are obtained by the exploratory activity, a simpler approach would be to limit the initial environmental statement for a frontier sale to consideration of impacts from exploratory drilling. Supplemental statements could be prepared as warranted to address development and production activities.

Air Quality

Emissions. The potential for air pollution caused by the exploration for oil and gas is quite small. For example, geophysical surveys do not contribute significantly to air pollution.

Drilling operations are temporary and relatively short term, from a few days or weeks to several months. Air emissions during drilling operations occur principally from engines developing horsepower to run the drilling rig and related equipment. Most drilling rigs and support equipment are powered by diesel engines, some with natural gas, and a small portion with electric power. Engine exhaust emissions contain NO_x, CO, unburned hydrocarbons, particulates, and some sulfur oxides (SO_x). The pollutant of greatest magnitude is NO_x.

Production operations emit the same type of pollutants as other industrial operations. In conventional oil operations, air emissions are well controlled and present few problems. Technology currently exists to control the SO_x emissions from steam generators used to enhance the production of heavy oil. NO_x control is continuing to show improvement.

In cases where sour gas (natural gas containing hydrogen sulfide) requires sweetening, various treatment methods are used. A sulfur recovery plant, generally followed by a tail gas treatment unit, can remove nearly all the potential sulfur emissions. Efficiencies of 99.7 percent are being approved as BACT on large sour gas plants that have been permitted in the Overthrust Belt.

In the future, PSD restrictions in or near Class I and possibly Class II areas could adversely impact oil and gas production activities. This situation would most likely occur in areas of complex terrain, such as exists in the Overthrust Belt. EPA's present modeling criteria for complex terrain situations make it extremely difficult for even small emissions of criteria pollutants to comply with the present PSD increment levels.

On March 7, 1980, USGS published final OCSLAA air emission regulations and draft air quality regulations applicable only to OCS activities offshore California. The regulations require that each proposed OCS facility be reviewed on an individual basis to determine its individual onshore air quality impacts, and be reviewed in conjunction with other nearby

OCS facilities to predict cumulative onshore impacts.

Examples of production losses encountered in developing onshore and offshore leases and of accelerating production of heavy oil in Kern County, California, are presented in the Energy Facility Siting section of this chapter. In spite of these problems, the majority of the exploration and production segment of the petroleum industry has been able to meet the requirements of the Clean Air Act. The larger projects generally get approved in less than one year. Permits for small- to medium-size projects are issued within three to nine months. In some cases, the cost of keeping a rig on standby for months is too costly and results in cancellation of the project.

Water Quality

Onshore Operations. The initiation of drilling operations has various impacts on the water environment, generally all short-lived and minor in nature. Drilling wastes mainly consist of used drilling fluid (mud) and formation solids (cuttings). Drilling mud is basically a suspension of clay in water. It usually contains barite for weight control and low concentrations of specialty chemicals to control viscosity, fluid loss, corrosion, and other mud properties. The cuttings are small pieces of rock produced by the drill bit penetrating the formation.

When drilling an onshore well, a reserve pit is used to store the drilling mud and cuttings and to serve as a means for final disposal. In certain areas, government regulations and unique geographic and/or environmental considerations require the use of an impervious liner in a reserve pit.

Once the well has either been completed or abandoned and the drilling equipment moved off location, three major methods of handling used drilling fluid are utilized (in order of prevalence):

(1) Dewatering pit wastes followed by backfilling the pit using the pit walls

(2) Landfarming the waste into the surrounding soil

(3) Vacuum truck removal to a state-approved disposal site.

The last method is specific to unique circumstances; i.e., environmentally sensitive and/or urban areas.

There is some concern that surface water, groundwater, and soil may be contaminated by the leaching of metals in trace quantities from buried reserve pits. The intrinsic characteristics of drilling mud greatly retard or prevent leaching from the reserve pit, especially after disposal, which should eliminate or greatly minimize such problems. Research projects are currently under way to clarify any environmental problems caused by abandoned buried reserve pits.

Section 404 of the federal Clean Water Act prohibits the discharge of dredge or fill material into "navigable waters" of the United States without a permit, and establishes the U.S. Army Corps of Engineers as the permitting agency. Thus, almost any construction activity in a pond, lake, river, wetland, tundra, or salt marsh requires a Section 404 permit. The Corps notifies other federal, state, and local agencies of all permit applications to solicit their review and comments prior to permit approval. Actual implementation of Section 404 of the Clean Water Act by the Corps has resulted in lengthy delays, up to 271 days, in the drilling of many oil and gas wells.

The major waste product produced in conjunction with oil and gas operations is produced water that exists naturally in an oil and gas reservoir. Produced water is brought to the surface with oil and gas, where it is typically removed by gravity separation. Once separated, the produced water can be reinjected in an underground disposal well.

The use of underground injection wells depends upon the availability of geologic formations that have sufficient porosity, permeability, and areal extent to contain the injected water. Usually, formations that already contain salt water are used. The major concern is that the produced water be confined and that it not contaminate underground sources of drinking water. State UIC programs regulate the reinjection of produced waters from exploration and production operations.

Offshore Operations. In offshore operations, water-based drilling muds are normally used. These low toxicity muds are discharged overboard in accordance with applicable state or federal regulations under the limitations set forth in individual NPDES or state permits controlling the discharges. EPA Region VI issued three General Permits covering the producing area of the Gulf of Mexico on April 29, 1981. These permits provided for overboard discharge of drilling muds and drill cuttings with a limitation of "no free oil" controlling the discharge. Discharges occur on a day-to-day basis, as the mud system is kept in balance for drilling operations. Numerous studies have shown that these discharges have

a minimum or negligible impact on the receiving waters.

Methods other than overboard discharge have been considered for disposal of drilling muds and cuttings. Transporting these materials to an authorized ocean dump site is one of the alternate methods proposed. The additional safety hazards of standby storage barges or boats at the drill site, the risk of collisions of these vessels in transit or loss due to unpredictable heavy seas, and the air pollution caused by the transport vessels must be considered with the advantage of transporting from one site to another for disposal. The same technical and safety problems are encountered for transporting these materials to shore for on-land disposal, which would also require additional land disposal facilities. Another alternate method to overboard discharging of drilling muds and cuttings for sensitive areas is the shunting or release of these materials through pipes well below the surface of the waters. If the sensitive area is on the ocean bottom, metered release and/or dilution of bulk discharges may be included as permit requirements.

Waste Management

As mentioned earlier, the major wastes generated by exploration and production operations are produced waters, waste drilling muds, and drill cuttings. In May 1980, EPA promulgated a very comprehensive set of RCRA regulations detailing a "cradle-to-grave" concept of handling and disposing of hazardous/toxic wastes. Exploration and production wastes were included in the proposed regulations as "special wastes," and were proposed to be regulated as hazardous wastes, due primarily to the presence of chromium and other metals in trace concentrations.

Under the 1980 amendments to RCRA, the wastes directly associated with exploration and production were exempted from RCRA. This amendment also directed EPA to make a two-year study of the degree of hazard of these wastes, after which Congress will consider whether or not to remove the exemption. As of October 1981, EPA had not initiated the study. An independent environmental consulting organization is investigating the environmental impact to surface water, groundwater, soil and vegetation from field disposal operations of drilling mud wastes and reserve pits.[11] The objective of the study is to determine if any constituents in drilling mud leach from pits containing drilling fluid wastes in sufficient quantities to present a significant hazard to human health or to plants or animals.

In the unlikely event that the exemption for drilling muds, produced waters, and associated waste is lifted and oil and gas industry exploration activities must comply with the full context of the EPA's proposed regulations, the costs could be as high as $31 billion (in constant 1978 dollars), and an additional $3.3 billion per year in direct operating and maintenance costs based upon the regulatory program proposed in December 1978.[12]

Even if Congress continues the RCRA exemption for exploration and production or chooses to regulate these wastes in a relatively modest manner, there will be continuing problems with the disposal of hazardous wastes due to the paucity of approved disposal sites. The increasing concerns of state and local governments with disposal sites may significantly impact the level of oil and gas development.

Refining

Industry Operations

Petroleum refining involves the processing of crude oil into usable petroleum products. The initial refining process separates crude oil into boiling ranges. These fractions are then processed by cracking the large hydrocarbon molecules into smaller ones. The structure of some of these molecules is rearranged and others are joined in different combinations to provide the desired components for blending into finished products. This takes place in a number of refinery process units, each with a specific purpose, integrated into a processing sequence.

The type and number of refinery process units in a given plant depends on the type of crude oil to be processed, product requirements, and economic factors such as crude oil costs, product values, and availability and cost of utilities and equipment. The type and size of processing units thus varies greatly. Theoretically, any petroleum or petrochemical product can be manufactured from any type of crude oil. Economically speaking, however, a refinery will be designed based on the available crude oil and the market demand for products.

There were 262 refineries operating in the United States in 1970, with a total operating capacity of 11.8 MMB/D. By 1980 there were 311 refineries in the United States, with 17.6 MMB/D of operating capacity.[13] Individual refineries range in size from 190 barrels per day of capacity to 640,000 barrels per day.[14]

The operation of a refinery can be divided into seven steps:

- *Separation of Crude Oil.* The most widely used methods for separating crude oil are atmospheric and vacuum distillation. Solvent extraction, absorption, and crystallization are also used, but to a much lesser extent.
- *Conversion of Hydrocarbon Molecules.* Conversion processes, which change the size or structure of the hydrocarbon molecule, convert some of the crude oil fractions into higher value products. The most common conversion processes are cracking (thermal, catalytic, viscosity breaking, hydrocracking, and coking); combining (alkylation and polymerization); and rearranging (catalytic reforming and isomerization).
- *Treating Crude Oil Fractions.* Some of the original sulfur compounds are converted to hydrogen sulfide, which can be separated and converted to elemental sulfur. Undesirable sulfur compounds are removed by treating processes such as hydrodesulfurizing and chemical treating.
- *Blending Hydrocarbon Products.* Most petroleum products are a blend of hydrocarbon fractions or components produced by various refinery processes. Motor gasoline is a blend of various gasoline blending stocks, including reformate, alkylate, straight-run naphtha, thermally and catalytically cracked gasoline, and necessary additives. The vast number of fuel oils, lubricants, and asphalt products are blends of refinery base stocks.
- *Auxiliary Operating Facilities.* A number of refinery units are used to maintain normal operating conditions. These units support processes such as hydrotreating, improve efficiency by allowing reuse of water and the use of sour gas as fuel, and help the refinery meet environmental standards. Included among the functions of auxiliary operating facilities are hydrogen production, light ends recovery, acid gas treating, sour water stripping, sulfur recovery, tail gas treating, and wastewater treatment.
- *Refinery Offsite Facilities.* Refinery offsite facilities are equipment and systems used to support refinery operations. These facilities include storage tanks, steam generating systems, flare and blowdown systems, cooling water systems, receiving and distribution systems, and refinery fire control systems. In addition, garages, machine shops, storehouses, laboratories, and necessary office buildings are considered offsite facilities.
- *Emission and Effluent Control.* Refineries generate air emissions, wastewater, solid waste, and noise, which must be controlled for efficient processing and environmental protection. The control of pollutants that can damage the environment is an important part of refinery operations.

Environmental Considerations

Refineries vary regarding crude oil input, types of process units, the type of products, and, therefore, pollution control technologies. Generally, pollutant discharges and emissions are kept to permissible levels by maximizing process unit efficiency and extensive treatment.

Air Pollution Control

Petroleum refineries are stationary sources of the conventional pollutants: particulates, sulfur oxides, nitrogen oxides, volatile organic compounds, and carbon monoxide. Emissions from petroleum refineries today represent only 0.5 percent of the nation's total TSP emissions, 2.8 percent of the SO_2, 1.5 percent of the NO_x, 3.9 percent of the VOC, and 0.9 percent of the CO.[15] Air emissions per barrel of crude oil processed have been reduced markedly over the past decade. A comparison of the 1970 emissions with those of 1979 is shown in Table 18. The significant reductions in air emissions were achieved in the refining sector during the past decade by improvements in process technology, increased use of hydrodesulfurization processes, and more widespread use of electrostatic precipitators, CO-boilers, and refinery fuel gas treaters that remove most of the fuel gas hydrogen sulfide. Hydrogen sulfide is generally recovered as sulfur or sulfuric acid.

Petroleum refinery emissions are expected to remain rather constant during the next decade. The NPC in 1980 projected that the most probable case will be a 4 percent decline in U.S. refinery crude oil runs in 1990.[16] Despite negative growth projections, refineries will continue to require large capital expenditures for new and modified facilities for upgrading poorer quality crude oils and other feedstocks. The modest further reductions in refinery air emissions normally expected by the replacement of older facilities will probably be offset by modest increases resulting from the processing of crude oils of poorer quality.

The sources of refinery emissions and the associated control technology are well defined and fully utilized. Capital investment in air pollution abatement facilities is estimated to be more than $250 for each barrel of daily product capacity.[17] Nevertheless, Clean Air Act requirements will continue to impose large

TABLE 18

REFINERY AIR EMISSIONS, 1970-1979*

	1970	1979	Percentage Reduction
Total Suspended Particulates (TSP)	18	9	50
Sulfur Dioxide (SO_2)	156	127	19
Nitrogen Oxide (NO_X)	78	64	18
Volatile Organic Compounds (VOC)	181	180	0
Carbon Monoxide (CO)	502	159	68

*Emission estimates in metric tons per 10^6 barrels of crude oil run based on 1970 = 10,870 MB/D, 1979 = 14,648 MB/D.
Source of data: Environmental Protection Agency, *National Air Pollutant Estimates, 1970-1979,* 1981; and American Petroleum Institute, *Basic Petroleum Data Book,* 1981.

uncertainties in the planning and development of facilities and has the effect of increasing project risk and costs. The requirement in nonattainment areas for LAER, defined as the most stringent limitation achieved in practice anywhere, for new or major modified sources without taking economic factors into account will obviously increase costs. The emission offsets policy has also been demonstrated to increase costs.

Adverse impacts of the Clean Air Act on the refining industry have been found to be various combinations of three general problems: undue uncertainty in project planning; avoidable delays in decision-making by review agencies; and unjustifiably stringent control technology requirements without commensurate air quality benefits. The principal causes of the impacts can be categorized as follows:

- Complex and inflexible statutory requirements for regulatory review, including:
  - Overlapping federal and state reviews
  - Complex regulations subject to frequent change during review proceedings
  - Lack of flexibility by review agencies in their interpretation of regulatory requirements
  - Operational problems within the review agencies (e.g., work overload, personnel turnover, inadequate communications).
- Implementation of the PSD program, including:
  - Disputes concerning PSD increment allocation
  - Lengthy and uncertain negotiations concerning case-by-case BACT determinations
  - Lengthy pre-application ambient monitoring requirements.
- Impractical nonattainment area requirements, including:
  - Excessively stringent and changeable LAER determinations
  - Unavailability of emission offsets.
- Technical difficulties, including:
  - Excessively conservative air quality modeling requirements
  - Use of unverified models to determine emission control requirements.

Water Pollution Control

Remarkable reduction in wastewater pollution discharge has been achieved by the refining industry in the past decade. Wastewater pollutant discharges for the segment of the refining industry that treats and discharges its own wastewater (direct dischargers) are shown in Table 19.

The refining industry as a whole has achieved a better than 91 percent reduction in

the discharge of conventional water pollutants from 1967 to 1979. Refinery process unit modernizations accounted for some of this improvement, but refineries made significant gains in the development of wastewater treatment technology and wastewater management programs and the subsequent utilization of these developments in operations. Specifically, during the past decade significant reductions in wastewater flow volumes per barrel of crude oil processed have been achieved in every refining subcategory. Median flow reductions determined from 1972 and 1977 refinery surveys for the subcategories were: topping, 67 percent; cracking, 47 percent; petrochemical, 59 percent; lube, 47 percent; and integrated, 56 percent. These water management improvements were supplemented with significant advances in the state-of-the-art of the following technology areas: sour water stripping; dissolved air flotation; granular media filtration; numerous biological wastewater purification processes; and water reuse practices.

The proposed BCT for 1984 will offer only marginal improvements over present discharge levels, yet would be costly to achieve. The means by which EPA previously estimated the cost effectiveness of proposed BCT regulations is the "cost reasonableness" test, in which the cost (in dollars per pound) of removing the additional increment of conventional pollutants at refineries is compared with costs at publicly owned treatment works (POTW). However, in July 1981, the U.S. District Court of Appeals for the Fourth District vacated all EPA regulations purporting to establish BCT effluent limitations under the Clean Water Act.[18] The Court held that the EPA's "cost reasonableness" test was insufficient, but the Court did not specify particular factors to be considered in such a test. EPA was directed to reconsider the "cost reasonableness" test.

In applying a "cost reasonableness" test, it has been estimated that incremental pounds of total suspended solids and biochemical oxygen demand removed after BPT treatment

TABLE 19

REFINING INDUSTRY EFFLUENT DISCHARGES, DIRECT DISCHARGERS

Conventional Water Pollutants	Thousands of Pounds Per Day (Annual Average)				
	1967*	BPT July 1977†	1979 Actual§	Proposed BCT July 1984‡	Percentage Reduction, 1967-1979
Biochemical Oxygen Demand (BOD)	800	71	38	28	95
Total Suspended Solids (TSS)	500	47	43	18	91
Oil and Grease (O&G)	360	24	13	9	96

*Crossley, S-D Surveys, Inc., "1967 Domestic Refinery Effluent Profile," report prepared for the American Petroleum Institute, September 1968.

†American Petroleum Institute, "Comments of the American Petroleum Institute Regarding the Environmental Protection Agency's Proposed Effluent Limitations Guidelines, Pretreatment Standards and New Source Performance Standards for the Petroleum Refining Point Source Category." O&G by ratio to BOD.

§Calculated using EPA variability survey data; Personal correspondence, July 12, 1981, Jitu Shaveri (ERT) to J.M. Rieker (Mobil), "Summary of 1979 Average Mass Discharges for BCT Parameters for Refineries Selected by EPA for Variability Analysis," and American Petroleum Institute, "Evaluation of Cost-Reasonableness of Best Conventional Technology Regulations for the Petroleum Refining Point Source Category," June 1980.

‡U.S. Environmental Protection Agency, "Petroleum Refining Point Source Category Effluent Limitations Guidelines, Pretreatment Standards," Proposed Rules 40 CFR 419 and 44 FR 75926, December 21, 1979.

would cost $5.39 per pound for refineries and $0.53 per pound for POTW.[19] Thus, if there are situations requiring further reductions in discharges of conventional pollutants, POTW are the economic choice to achieve any needed reductions beyond BPT. Any possible reductions by refineries are so marginal and costly that the BCT limitations should remain at present BPT levels.

Comparable data are not available for the nonconventional pollutants, which are designated as ammonia, chemical oxygen demand, sulfides, and total organic carbon; however, the existing discharge levels for the industry as a whole meet both existing and proposed limitations using BPT treatment systems.

The refining sector has been surveyed extensively as a potential source of 65 priority pollutants and classes of pollutants and no serious problem areas were found. Concurring, EPA found that "BPT treatment substantially reduces toxic pollutant concentrations. Most toxic pollutants are reduced to near or below the concentrations considered accurate for use in the Analytical Protocol developed by the Agency."[20] Recognition that refineries are not a significant source of priority pollutants is illustrated by the fact that the proposed Best Available Technology Refinery Effluent Guidelines include only three "toxic" pollutants: phenolics, total chromium, and hexavalent chromium.

Waste Management

The present hazardous waste management regulations, promulgated under the authority of Subtitle C of RCRA, utilized a threshold regulatory approach. A given waste stream will be designated hazardous if it is specifically listed within the regulations, it is a discarded or off-specification commercial chemical product or spill residue, or it exhibits any of the following four characteristics identified by EPA: ignitability, reacticity, corrosivity, or toxicity. The present program regulates all hazardous wastes utilizing identical technical and administrative controls. The program fails to recognize the significant variation in the degree-of-hazard of wastes. Therefore, many large-volume wastes in the refining sector must be disposed in secure hazardous waste management facilities, thereby contributing to an anticipated shortfall of needed capacity to dispose of truly hazardous wastes.

EPA is re-evaluating the cost effectiveness of the present regulatory approach and began a study in November 1981 to evaluate refinery waste streams regulated under RCRA. The ultimate goal of this study is to promulgate a subset of RCRA regulations specifically addressing refinery waste streams.

Refinery wastes listed in 1980 as hazardous under RCRA regulations are summarized in Table 20. The listed hazardous wastes were so designated because of their potential for containing lead and/or chromium. Individual refinery sources can be evaluated for hazardous designation by using an EPA testing protocol, and some refineries have obtained delisting of wastes based on test protocol results.

TABLE 20

HAZARD WASTES OF THE REFINING INDUSTRY AS DEFINED BY THE RCRA REGULATIONS (MAY 1980)

Listed	Hazardous Waste Streams §261.32
K048	Dissolved air flotation (DAF) float
K049	Slop oil emulsion solids
K050	Heat exchanger bundle cleaning sludge
K051	API separator sludge
K052	Tank bottoms (leaded)

Petroleum refineries were estimated to generate about 1.9 million wet metric tons of hazardous waste in 1980, about 5 percent of the total hazardous wastes generated in the United States.[21] The refining industry currently treats and disposes of 70 percent of its own RCRA hazardous wastes using land-based technology. The RCRA hazardous wastes land disposal permitting standards were proposed and withdrawn in 1981. EPA has projected the date of final promulgation of these standards to be January or February 1983. EPA has distinguished land disposal from land treatment and made a research commitment at laboratories in Ada, Oklahoma, to assess the effectiveness of land treatment technologies.

Landfarming, bio-oxidation, composting, and related low-cost, self-sustaining, highly efficient, and environmentally enhancing technologies are expected to be the basis for hazardous waste disposal systems for the next generation. In many parts of the country, these methods can be implemented on property that is owned and controlled by the petroleum companies without encroaching on private or municipal domains.

Presently available information regarding petroleum industry hazardous waste streams is inadequate. An industry-wide waste inventory is needed to identify hazardous waste streams by source and quantity.

Storage, Transportation, and Marketing

Industry Operations

The oil and gas industries' storage, transportation, and marketing facilities represent two large, complex collection and distribution systems. One system transports crude oil and other raw materials to refineries; stores raw materials, intermediates, and products; and distributes finished petroleum products to the consumers. A separate system moves natural gas from producing areas to the consumer. These systems have developed and improved over the years, resulting in greater efficiency, safety, convenience, energy conservation, and improved protection of the environment.

The complexity of the network for petroleum storage, transportation, and marketing is illustrated by 1980 statistics showing that in the United States approximately 543,000 crude oil producing wells[22] fed 311 refineries,[23] which provided gasoline and oil to 15,000 terminals and bulk plants feeding 158,000 service stations[24] serving 122 million passenger automobiles,[25] and provided many other products for home and industrial use.

Storage

The petroleum industry requires storage facilities for tremendous volumes of raw materials and refined products. Tanks are required for crude oil and liquid products; pressure vessels and underground storage are used for natural gas liquids; and underground reservoirs and cavities are used for natural gas. Primary storage is located at strategic points along the distribution system: at points of transfer between transportation modes, at points where a number of pipelines converge, and at manufacturing facilities and distribution terminals. Secondary storage is maintained by consumers and small distributors of petroleum products further removed from the primary distribution system.

Facilities can be divided into storage for liquid petroleum or natural gas, and further subdivided for discussion to above-ground and below-ground. Above-ground storage is used mostly for crude oil and refined petroleum products such as gasoline and distillates. Underground storage is most commonly used for natural gas and liquefied petroleum gas.

A 1978 NPC survey determined that the U.S. primary distribution system had a storage capacity of over 1.5 billion barrels for crude oil, gasoline, kerosine, and fuel oils. The NPC also estimated secondary storage capacity for gasoline and distillate fuel oil to be at least 500 million barrels in 1978.[26] Underground storage capacity for natural gas in 1979 was 7.4 trillion cubic feet.[27]

Transportation

Oil and gas and their products are transported through an interconnected system of pipelines, tankers, barges, tank cars, and tank trucks. (See Table 21 for a summary of U.S transportation facilities.)

Petroleum pipelines normally carry either crude oil or petroleum products, although some pipelines carry both. Domestic crude oil is moved by pipeline from producing oil fields to refineries and imported crude oil is moved by pipeline from ports to refineries. Petroleum product pipelines move refined products from refineries to terminals from which distributors move them to market. Separate pipeline systems move natural gas from producing areas to the consumer.

Tankers and barges transport very large volumes of crude oil and petroleum products—more petroleum is carried on water than is any other commodity. Domestic traffic is composed of barges and lake and coastal tankers; foreign commerce occurs by means of ocean-going vessels. Over the last decade, world tanker capacity has increased markedly; 1971 capacity was 169,354,743 DWT (1.3 billion barrels) and 1980 capacity was 339,801,719 DWT (2.5 billion barrels).[28]

Tank cars and tank trucks are used extensively by the petroleum industry to transport finished products to bulk plants and consumers and to move a considerable amount of domestic crude oil from gathering areas to refineries, particularly in areas where pipelines are not available. Tank trucks are extremely flexible for delivering relatively small quantities of petroleum products on short hauls, especially home heating oil from bulk plants to customers and gasoline from terminals and bulk plants to service stations.

Marketing

While marketing systems exist for all petroleum products, the system for automotive gasoline is by far the most extensive system, and provides outlets for the industry's principal product.

Automotive gasoline is generally transported from a refinery or terminal to service stations; individual, large-volume consumers; or small bulk plants, which in turn normally direct it to service stations or large-volume consumers. The total consumption of automotive gasoline is expected to decrease over the next decade, and industry trends indicate that

TABLE 21

OIL AND GAS TRANSPORTATION FACILITIES

	Number of Units	Total Capacity
Gas Pipelines* (as of 12/31/77)	331,976 miles	NA
Petroleum Pipelines† (as of 12/31/78)	227,060 miles	NA
Tank Cars§ (as of 7/15/79)	107,552	2,175.5 MMgal
Tank Trucks§ (as of 12/31/79)	50,000	364.4 MMgal
Tank Barges§ (as of July 1979)	3,971	71.4 MMbbl
Tank Ships§ (as of July 1979)	352	97.0 MMbbl

*Includes gathering lines; excludes distribution lines.
†Includes gathering lines.
§Suitable for petroleum transportation.

SOURCE: National Petroleum Council, *Petroleum Storage and Transportation Capacities*, 1979.

the number of service stations will decrease even more. Consequently, the average station will handle an increased volume of products.

Light-oil petroleum products are generally shipped from refineries by pipeline or barge to terminals and bulk plants, where they are stored in above-ground tanks at tank farms. These products are then transported by truck to homes, service stations, and large-volume consumers.

Major airports receive petroleum fuels by pipeline connected directly to one or more refineries. The aircraft are fueled through a hydrant fueling system buried beneath the aircraft loading and service areas or by special refueling trucks.

Environmental Considerations

The storage, transportation, and marketing of petroleum raw materials and products are conducted in a predominantly closed system—tankers, barges, storage tanks, pipelines, tank cars, tank trucks, and service station underground tanks. This closed system acts to protect product quality, ensure the safe handling of materials, and minimize releases to the environment. Some releases do occur at points of transfer, during storage, during equipment maintenance and cleaning, through accidental spills, and through disposal of used petroleum products (such as lubricating oils).

The selection of a site for a storage terminal, marine terminal, marketing facility, or a pipeline route is based on a number of factors, of which environmental permits are among the most important. Other factors, which may be overriding, include the availability of land, access to existing modes of transportation (rail, waterway, highway), proximity to the market, availability and source of products and raw materials, and unique environmental considerations. The present permitting process has introduced considerable delays and uncertainty into the facility siting process.

Air Pollution Control

Emissions of hydrocarbons and NO_x are the primary air pollutants of concern. Hydrocarbon emissions can occur at many points

throughout the distribution system, primarily during storage and at points of transfer. NO_x emissions arise from fuel-burning engines used to drive pumps and compressors that move materials through the distribution system. Emissions of these pollutants are the subject of environmental regulations and they are controlled by a variety of techniques. Floating roof tanks effectively control storage losses. Emissions from loading of tankers, barges, and tank trucks are limited by using submerged fill procedures, and by supplemental vapor recovery where needed. Service station vehicle refueling losses can be controlled by a vapor balance system or a vacuum assist system.

Total emissions from storage, transportation, and marketing facilities are widely dispersed geographically and are difficult to estimate with a high degree of accuracy. National emission estimates for 1979 show VOC emissions of 24.6 million metric tons. About 0.6 million metric tons are estimated to result from crude oil production, storage, and transfer, and about 1.8 million metric tons are estimated to result from petroleum product storage and transfer.[29]

Trend data show little or no increase in emissions despite substantial increases in crude oil and gasoline throughput, reflecting the extensive implementation of VOC emission controls. Future downward emission trends are expected because of the further application of controls and decreased liquid fuel consumption.

Controls on vehicle refueling emissions, which have been implemented in some areas and are under consideration in others, may not achieve their intended purpose. EPA has not demonstrated that these controls will have any measurable positive impact on air quality and the costs are large compared to the environmental benefits.

Water and Land Pollution Control

Industry practices and environmental regulation control the discharges of raw materials or products to surface waters and to the land (where they can contaminate groundwaters). This control is through both the treatment of contaminated wastewater before discharge and an intensive system of spill prevention, including design and equipment changes and training. In addition, as spills can never be 100 percent prevented, spill contingency plans have been prepared to cover the detection and cleanup of spills when they occur.

Discharges to surface waters from storage, transportation, and marketing facilities result primarily from storm water runoff, process wastewater, and spills. Contaminated water is treated before discharge and, as a result, produces little in the way of environmental impact.

Leaks from underground gasoline tanks and connecting pipes at service stations have received increased attention in recent years. These sources may contaminate groundwaters and may create fire and explosion hazards whenever service stations are located near homes or businesses. The petroleum industry has developed a multi-faceted industry program to prevent and control leaks. In addition, there is a continuing industry trend to replace underground steel tanks with corrosion-resistant fiberglass reinforced plastic, and to employ aggressive leak-detection programs.

Waste Management

Industry practices have been and continue to be developed to ensure proper handling of waste materials. With the promulgation of hazardous waste management regulations in May 1980, and the enactment of Superfund in December 1980, there has been an increased awareness of overall waste management practices, including the proper handling and disposal of used lubricating oils. Congress enacted the Used Oil Recycling Act in 1980 to encourage the use of recycled oil to avoid threats to public health and the environment, and to conserve energy and materials. The Act requires EPA to make a determination whether used oils should be regulated as hazardous waste under RCRA.

EPA published a Report to Congress in January 1981, "Listing Waste Oil as a Hazardous Waste," and prepared some draft regulations. EPA's intention to regulate used lubricating oils as hazardous wastes has caused concern within the industry, as it would produce large impacts in the marketing segment. These impacts could result from regulatory entanglements that will actually discourage the recycling of used oils through increased paperwork, monitoring, recordkeeping, and requirements on used oil collectors.

Product Use

The petroleum industry produces a wide variety of products, but approximately 87 percent of the total volume becomes fuel for stationary combustion equipment and transportation.[30] Non-fuel uses include petrochemical feedstocks, asphalts, and lubricants. Table 22 contains a partial list of products. Fuel products impact on the environment primarily

TABLE 22

MAJOR PETROLEUM PRODUCT USE BY SECTOR, 1980*

	Million Barrels	Percentage of Total
Fuel Products		
Industrial Sector		
Distillate Fuel Oil	257	4.1
Residual Fuel Oil	258	4.1
Liquified Gases	169	2.7
Motor Gasoline	28	0.4
Kerosine	21	0.3
Natural Gas†	—	—
Other	304	4.9
Residential and Commercial Sector		
Distillate Fuel Oil	353	5.7
Residual Fuel Oil	86	1.4
Liquified Gases	136	2.2
Kerosine	38	0.6
Natural Gas†	—	—
Motor Gasoline	20	0.3
Transportation Sector		
Aviation Gasoline	13	0.2
Distillate Fuel Oil	401	6.4
Jet Fuel	387	6.2
Motor Gasoline	2,362	37.9
Residual Fuel Oil	132	2.1
Liquified Gases	2	< 0.1
Electric Utility Sector		
Distillate Fuel Oil	39	0.6
Jet Fuel	2	< 0.1
Residual Fuel Oil	438	7.0
Other	1	< 0.1
Subtotal	5,447	87.1
Non-Fuel Products		
Industrial Sector		
Ethane	123	2.0
Liquified Gases	111	1.8
Lubricants	30	0.5
Petrochemical Feedstocks	251	4.0
Petroleum Coke	17	0.3
Special Naphthas	36	0.6
Wax	6	0.1
Natural Gas†	—	—
Miscellaneous	39	0.6
Residential and Commercial Sector		
Asphalt and Road Oil	146	2.4
Transportation		
Lubricants	28	0.4
Subtotal	787	12.7
TOTAL	6,234	100.0

*Source of data: Energy Information Administration, *1980 Annual Report to Congress*. Volume II. Totals may not add due to rounding.

†Natural gas not included in totals.

through combustion and the resulting emissions and, therefore, are subject to environmental regulations.

Stationary Sources

Petroleum products are widely used for electric power generation, domestic and commercial heating, and manufacturing. They generate emissions of SO_x, NO_x, particulates, CO, and unburned hydrocarbons. Of these, SO_x from fuel oil combustion represented approximately 16 percent of the total SO_x from all fuel combustion in 1979.[31] The sulfur content of fuels used in power generation and space heating is limited by regulations in many areas of the country. In order to meet these sulfur limitations, the refining industry installed fuel oil desulfurization equipment. As of January 1, 1981, there were 2.0 MMB/D of desulfurization capacity, representing approximately 11.1 percent of the total crude oil capacity of 18.0 MMB/D.[32] Sulfur limitations also stimulated demand for low-sulfur imported crude oils and the low-sulfur fuel oils produced from them, placing higher sulfur crude oils at a competitive disadvantage.

The price differential between coal and crude oil and the requirements of the Fuel Use Act, together with the slowdown in the rate of economic growth, have caused a decrease in the demand for heavy fuels. The petroleum industry has adjusted to changes in crude oil sources, refining technology, and market distribution, and is able to satisfy the demand for low-sulfur heavy fuels. Limits on the technology and present facilities could be serious in the West Coast markets—especially in California, where extremely low sulfur levels are being sought by regulators. The cost of low-sulfur fuels on the open market is now subject to competitive forces and there is an appropriate price differential reflecting the higher cost of manufacturing the low-sulfur fuel. In addition, environmental restrictions on the burning of coal have increased the demand for low-sulfur oils.

Pollutant controls on NO_x and TSP have been generally applied to the combustion source directly; they do not impact on the availability and cost of the products except as they apply to the fuel combustion sources in the industry.

Mobile Sources

About half of the petroleum products consumed are used as transportation fuels, and about half of that amount for automobiles. Other modes of transportation consume petroleum fuels in much lesser proportions; e.g., trucks (26 percent), aircraft (8 percent), marine vessels (7 percent), railroads (3 percent), pipelines and other transportation uses (3 percent), and buses (1 percent).

Each product impacts the environment according to its physical properties, combustion characteristics, and volume of use. For example, CO and VOC emissions come mostly from gasoline-fueled automobiles, while particulates, NO_x, and SO_x emissions come mostly from diesel combustion. Aircraft, marine, railroad, and bus emissions vary, but have little environmental impact because of their proportionately low product volume use. Lead emissions, once an important environmental concern, are no longer a major issue as a result of the lead phasedown regulations and the increased demand for unleaded gasoline.

The market for unleaded gasoline is about half of the total gasoline demand and is projected to reach 92 percent by 1990.[33] It is the creation of strict exhaust emission standards requiring the use of catalytic controls, which are partially deactivated by lead.

Pre-catalyst techniques for limiting emissions, such as engine modification, have impaired to varying degrees the quality of road operability of the automobile and have exacted a price in fuel economy, as evidenced by the 1973-1974 model year cars, the most fuel inefficient in recent history. Catalytic emission controls, introduced with the 1975 model year, made it possible to meet the much more stringent 1975 exhaust emission standards with an operable vehicle having acceptable fuel economy.

Octane restrictions accompanying the widespread manufacture and distribution of unleaded gasoline limit engine compression ratio, also a factor in fuel economy. In addition, for a given octane rating, unleaded gasoline costs more to refine and yields less gasoline per barrel of crude oil than does leaded gasoline.

Since 1975, there has been a trend towards increased fuel economy for new automobiles, with market demand often making Corporate Average Fuel Economy better than statutory requirements. Nevertheless, ever more severe emission standards have exacted new fuel economy penalties, even with catalysts. Furthermore, market demand for higher octane unleaded gasoline has so stimulated supply as to encourage car makers to abandon longstanding policies to limit car octane requirements to 91 Research Method octane rating (87 octane antiknock index).

The severe exhaust emission standards now in place for automobiles were developed at a time when it was believed that air quality would respond to a simple "rollback" in emissions from mobile sources. Subsequent experience has shown this assumption to be valid only for an unreactive pollutant like CO.[34] Moreover, the costs of such severe control have been high, in the billions of dollars.

Natural sources of the photochemical oxidant precursors, hydrocarbons and NO_x, contribute to ozone formation and complicate the problem of developing effective control strategies. Periodic incursion of ozone from the stratosphere further complicates strategy development.

The degree to which automotive emissions should be controlled should be re-evaluated on a cost-effectiveness basis. Enough has been learned in the last decade to support an analysis that considers not only the feasibility of vehicle controls as a means to achieve air quality standards, but the trade-off between energy consumption at the vehicle and at the refinery as well.

Major new mobile source issues that remain to be resolved either technically or politically will affect the future growth of diesel fuel use for automobiles and the introduction of alternative fuels. The health impacts of "unregulated pollutants," especially diesel particulates, presently are unknown. Methanol is being considered as an alternative fuel for transportation.

Fate and Effects of Spills

Introduction

Oil spills, large and small, have long been of concern. More recently, hazardous substance spills have received considerable attention, primarily outside the petroleum industry. Section 311 of the Clean Water Act as amended in 1978 specifically addresses spills of oil and hazardous substances. The Act prohibits the discharge of oil and hazardous substances in quantities "which may be harmful." Spills must be reported and civil penalties are assessed accordingly. Failure to report a spill can subject the discharger to criminal penalties.

Great attention has been focused on actual and potential oil spills although spills contribute only slightly over 6.2 percent of the total amount of petroleum entering the oceans annually.[35] (Table 23 shows the major sources of petroleum entering the ocean.) Less attention has been focused on hazardous substance spills because they are less frequent, less spectacular, smaller, and have much more localized environmental impacts.

Oil and hazardous substance spills attributable to the petroleum industry can result from both land- and marine-based activities of all segments of the industry. However, the hazardous substance spill regulations have the largest potential impact in the refining segment.

TABLE 23

SOURCES OF PETROLEUM ENTERING THE OCEAN*

	1975	
	Million MTA†	**Percentage of Total**
Urban Runoff	0.3	5
River Runoff	1.6	26
Coastal Facilities	0.8	13
Transportation		
Operations	1.833	30
Accidents	0.3	5
Offshore Production	0.08	1
Natural Seepage	0.6	10
Atmospheric Fallout	0.6	10
Total	6.113	100

*Source of data: National Academy of Sciences, *Petroleum in the Marine Environment*, 1975; based on 1973 estimates. Updated estimates are expected to be published by the NAS in 1983.
†MTA = metric tons per annum.

Hazardous Substance Spills

The petroleum industry as a whole is a minor source of hazardous substance spills. The quantities of hazardous substances used within the petroleum industry are small relative to the volumes of oil handled. Spills, when they occur, may produce localized impacts. While these can be serious in terms of such impacts as fish kills, they are temporary and do not pose long-term problems.

A few materials on the hazardous substance list are used in refineries as treatment chemicals, lube oil process solvents, and additives. Those that are used include ammonia, benzene, chlorine, furfural, hydrofluoric acid, phenol, sodium hydroxide, sulfuric acid, tetraethyl lead, and toluene. They are handled with

care, and when spills occur they are typically contained within tank dikes or removed during wastewater treating operations so that harmful releases to navigable waters are minimal.

Materials on the hazardous substance list are diverse. As a result, their environmental impacts are substance specific. Some are completely soluble in water (sodium hydroxide) while others are relatively insoluble (toluene). As a result, spill cleanup actions may be very difficult in many cases and impossible in others.

Hazardous Substance Spill Data

As a result of the reporting requirements of the Clean Water Act, the U.S. Coast Guard maintains extensive data on reported spills of oil and hazardous substances. The data on hazardous substance spills show the trends illustrated in Figure 11.

Preliminary hazardous substance spill data for 1980 show that of the total of 625,465 gallons spilled, 6 percent was from vessels, 3 percent from land vehicles, 72 percent from nontransportation sources, 7 percent from pipelines, 10 percent from marine facilities, and 2 percent unknown. Within these categories, refinery spills contributed 5 percent to the overall volume and no spills were reported from production operations. Preliminary dry bulk spill data for 1980 show the entire U.S figure to be 1,230,418 pounds. Of this amount, 2 percent was from vessels, 0.2 percent from land vehicles, 2 percent from nontransportation sources, and 95 percent from chemical pipelines. Within these categories, refinery spills contributed only 0.2 percent and no spills were reported from production operations. Other specific data for the petroleum industry were not broken out.[36]

Oil Spills

While oil spills are probably the most visible and well-recognized of accidental releases, their effects are reversible and generally not long term. Long-term studies of the marine ecosystem have shown that fluctuations occur during the recovery period after a spill. From the knowledge of similar untainted ecosystems, fluctuations of this kind are within the normal range of variability. It is more realistic to regard recovery as the restoration of a healthy, dynamic ecosystem, rather than the restoration of a pre-event status, that itself may not be known.

Studies following the 1970 Chevron Main Pass Block 41 spill in the Gulf of Mexico, the 1977 Ekofisk oil spill in the deeper waters of the North Sea, and even the very large oil discharge from the Ixtoc blowout in the Bay of Campeche in 1979, indicate few or no measurable adverse effects in offshore waters.

Most oil spills, even those impacting coastal areas, have not had serious long-term effects. Recovery has been relatively rapid in most situations, particularly in relation to productivity and marine pollution. Oil pollution poses much less of a threat to the marine environment than its visual prominence would imply. Contrary to earlier expectations, it is now evident that the losses of sea birds through oil pollution and other causes, though heavy, have had no detectable impact on breeding populations.

Oil Spill Data

Data on oil spills show the trends illustrated in Figure 12. Preliminary oil spill data for 1980 showed that of the total of 7,332,699 gallons spilled, 45 percent was from vessels, 2 percent from land vehicles, 12 percent from nontransportation sources, 23 percent from pipelines, 10 percent from marine facilities, and 6 percent unknown.[37]

Oil Spill Control Measures

Prevention of spills is the first line of defense in protecting life, property, and the environment. Effective prevention plans can reduce spill incidents and these plans are widely used throughout the petroleum industry. However, spill prevention is not 100 percent effective and some spills do occur. Spill contingency plans have been implemented to respond to spills, spill cleanup cooperatives have been formed, and a variety of spill control and cleanup techniques have been developed.

If conditions permit, oil spills may be contained and recovered by purely mechanical methods. These include the use of containment booms, oil skimmers, sorbents, and other devices. Equipment and procedures for containing and recovering oil spills in protected waters are well developed. In addition, some of these devices are effective in open waters under moderate conditions. Containment devices that will restrict the movement of oil in the open sea under extreme adverse conditions are not available.

While containment and recovery of spilled oil provides the most positive control, the use of such measures is not always possible. Nature itself has enormous capacity for disposing of hydrocarbons, and man can hasten the process. Many microorganisms in both

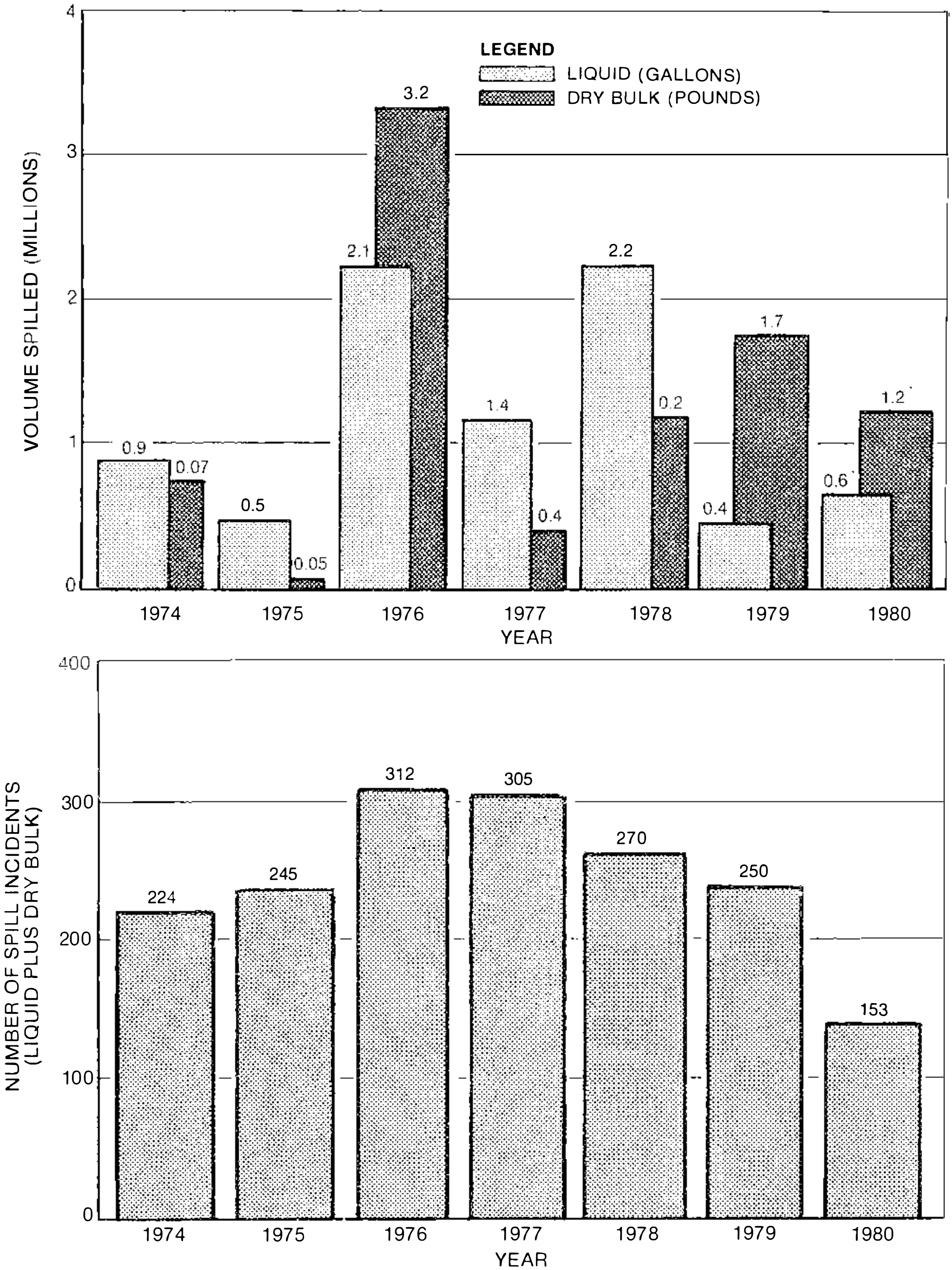


Figure 11. Hazardous Substance Spill Trends.

*Preliminary data.

SOURCE: Department of Transportation, Coast Guard, *Polluting Incidents In and Around U.S. Waters*. Calendar Years 1979 and Preliminary 1980.

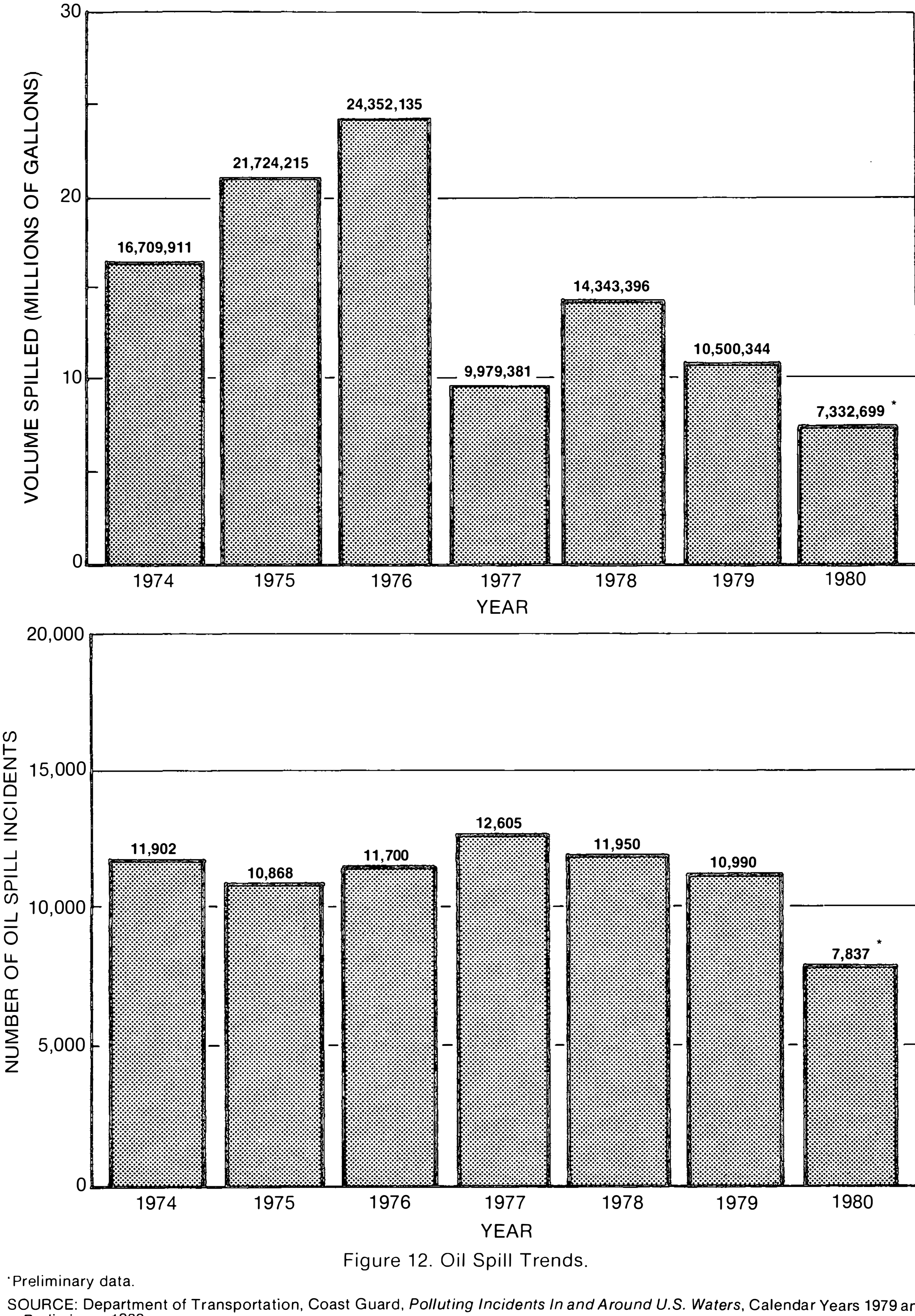


Figure 12. Oil Spill Trends.

*Preliminary data.

SOURCE: Department of Transportation, Coast Guard, *Polluting Incidents In and Around U.S. Waters*, Calendar Years 1979 and Preliminary 1980.

saline and fresh water can degrade hydrocarbons. In many circumstances, the best treatment of an oil spill would be natural dispersion by wind, waves, and currents and the accompanying microbial degradation. Due to the necessity to protect resources from immediate damage, this natural treatment frequently cannot be used, except when prevailing winds and currents carry the oil away from shorelines and areas of habitation, recreation, and commerce. As a result, oil spill treatment methods have been developed, the most effective being dispersants.

Dispersants break the oil into small particles that mix into the water column where they are removed by natural processes. They have been successfully used worldwide, but, to date, their use has been restricted in the United States. With improved dispersants and application techniques (aerial spraying), it is likely that dispersants will be used more widely and frequently.

Burning the oil can also be an effective mitigating action in appropriate situations. Burning slicks has been attempted with little success, but if conditions and circumstances allow, the burning of oil still contained in a stricken vessel can be a very effective way of reducing the amount of oil spilled into the sea.

The National Spill Contingency Plan (NSCP) provides for coordinated and integrated responses by departments and agencies of the federal government to protect the environment from the damaging effects of pollution discharges. The NSCP is being updated and a revised version should be available in early 1982. It is designed to discover spills, provide for timely notification, initiate containment, and provide for cleanup and disposal if the discharger is unknown or inadequate to the task.

The petroleum industry is committed to the cleanup of its own spills. In many cases, spill cleanup equipment and services are pooled in oil spill cooperatives promoted by member companies whose common purpose is to contain and clean up a spill in a designated area. In 1980, there were approximately 93 co-ops in operation in 43 states.

Effects of Oil

Major spills in the open ocean are more likely to involve crude oils because they are the largest volume of oil transported by sea. Crude oil spills can also occur from offshore blowouts and pipeline breaks. Although fish and benthic organisms may be present in large numbers, surveys have shown no adverse effects on adult fish or other macroorganisms. The dilution potential of the open sea and the dispersion, weathering, and loss of toxic constituents make it improbable that oils spilled in deep sea areas could reach benthic marine life, much less in toxic amounts.

The two potential dangers posed by oil in the open sea are effects on sea birds and on plankton (algae, eggs, larvae, and fry of adult animals, some of which inhabit near-surface waters). The latter type of life forms are numerous, reproduce in large quantities, and are subject to high natural mortality. The impact of an oil spill would probably not be sufficiently large to affect adult populations widely or for long.

Concern has been expressed that a number of biological effects can result from the large amounts of oil entering the sea, whether from oil spills, other sources attributable to man, or from natural seeps. Such postulated effects include disruption of bacterial populations, oil layer phenomena that would prevent normal gas exchange at the sea surface, local heating effects caused by solar heat absorption in oil slicks, and concentration of pesticides and heavy metals by oil. Despite careful study, no evidence has been obtained to support these claims. Fears of extensive mortality of marine animals from oil spills have not been substantiated.

Oil spills that impact shorelines have shown effects on sea birds and, in some instances, benthic organisms. Improper measures taken to remove the oil can inflict losses exceeding those due to the oil itself. These include bulldozing of beaches or steam-cleaning of rocky shorelines. Especially sensitive to oil are near-shore ecosystems such as coral islands, salt marshes, and mangrove communities.

It should be noted that most oil spills, even those that have impacted coastal areas, have evidently not had serious long-term effects. Recovery has been relatively rapid in most situations, particularly in relation to productivity and population. Careful study may reveal subtle long-term effects. Following the *Torrey Canyon* spill, the age structure of some rocky-shore populations showed some abnormalities for up to 10 years. These effects, however, had little ecological consequence.

Many factors influence the seriousness of an oil spill. The most important are the volume and type of oil, weather and sea conditions, the season, and the body of water where the spill occurs (the geography). The

greatest damage to marine life from a spill will occur when:

- The oil is spilled into or reaches a confined, shallow body of water, such as a small bay, and the volume of oil spilled is large with respect to the body of water being impacted.
- The oil is a light, refined oil such as a home heating oil or a diesel fuel.
- There is a high load of fine sediment in the water column due to storms, heavy surf, or the discharge of rivers.

Spills are rare in which all of these conditions occur simultaneously. Examples of when they did include the spill near West Falmouth, Massachusetts, in 1969, and at Baja California (Mexico) in 1957. In both cases the benthic sea life experienced heavy immediate mortality and their populations were reduced very locally for several years.

Many spills that threatened to have long-term major effects have not produced them; e.g., the Santa Barbara spill and the San Francisco Bay tanker spill. Near-shore oil spills involving crude oils, such as the *Amoco Cadiz*, the *Torrey Canyon*, and the *Metula* spills, do inflict substantial biological damage, but such damage is mitigated by the lower toxicities of crude oils compared to some refined products.

Energy Facility Siting

The permitting process under which the industry operates today is costly, complex, and cumbersome. While not all problems related to siting are environmental, environmental legislation and regulations have become a major factor in the siting process. The exact extent of additions to lead time for projects due to environmental concerns varies widely from project to project, depending upon which permit requirements apply to an individual case and what difficulties they present.

Environmental Impact Statements

One of the major components of the permitting process is the EIS. Whether a private industrial project will require preparation of a federal EIS depends upon whether all permits and approvals required for the project are exempted from NEPA requirements by the lead federal agency.

Three important actions that are subject to NEPA include:

- OCS leases
- The issuance of dredge and fill permits by the Corps of Engineers
- The issuance of RCRA permits.

Two actions that are exempt from NEPA are the following:

- The Clean Water Act excludes from NEPA all actions by EPA except the issuance of NPDES permits to new or modified sources in states where EPA continues to administer the NPDES program.
- Approval of industrial projects under state CZM programs does not require a federal EIS under NEPA.

While a project may be exempted from federal EIS requirements under NEPA, 18 states have adopted laws or regulations similar to NEPA that will subject the project to a state EIS. In addition to the laws and regulations at the state and federal level that contribute to the complexity of the permitting process, local governments have taken a much more active role in the process, both through environmental and zoning requirements.

The Department of Energy has estimated that over 200 of the 400 permits required for an oil shale development project are directed to environmental matters.[38] On the state level alone, for example, Utah requires an energy project to have 69 permits: 16 exploration, 31 environmental, 12 municipal and county, and 10 special use.[39]

Regulatory Uncertainties and Project Lead Time

The biggest uncertainty that exists in the area of facility siting is the extent of delays caused by permit review procedures. The length of the delay will vary from case to case, depending upon the type of environmental problems presented, the success of the company in gathering all of the data called for to meet government requirements, and the overall political acceptability of the project in the surrounding community.

Even with the best foresight, the regulatory process will add to the lead time for a project. To obtain data needed for the review process, engineering plans have to be completed at an early stage in the project-planning schedule. Actual construction cannot begin until many of the requisite approvals are obtained. As a result, the regulatory process greatly extends the time period previously experienced between the completion of engineering plans and the commencement of construction.

Many of the environmental approvals can be obtained, at least theoretically, within several months after an acceptable application has been submitted. However, others will take

not months but years. For most large industrial projects, such as a new oil refinery, petrochemical complex, or oil shale project, the acquisition of required approvals is likely to take two to four years.

Specific Examples of Delayed, Denied, and Abandoned Energy Projects

To provide an overview of the types of delays discussed in this report, the following list of projects delayed or cancelled as a result of government constraints is presented.[40]

- *Santa Ynez Unit*, California Outer Continental Shelf; 27 MB/D of oil and 30 million cubic feet of natural gas per day. The project was delayed for seven years by federal, state, and local regulatory obstacles. There were three major environmental impact studies, 21 major public hearings, 10 major government approvals, 51 consultant studies, and 12 lawsuits involving the project, some initiated by the project. After an investment of more than $380 million, the project finally began producing oil in April 1981.
- *PACTEX, Sohio marine terminal and pipeline*, Long Beach, California, to Midland, Texas; 500 MB/D. This pipeline was intended to carry Alaskan crude oil to Midland, Texas, and then to the Midwest. The project was cancelled after it became uneconomic following a five-year delay in obtaining the necessary federal, state, and local air quality permits.
- *Hampton Roads Energy Company oil refinery*, Portsmouth, Virginia; 170 MB/D. An eight-year delay was caused in large part by needed EPA approval of the SIP under the Clean Air Act and a needed dredge and fill permit from the Corps of Engineers. The project was cancelled in part due to the decreased need for refinery capacity by the time the permit was obtained.
- *Pittston oil refinery*, Eastport, Maine; 250 MB/D. The project has been delayed because EPA, to protect the habitat of the bald eagle, declined to issue a water pollution discharge permit.
- *Seadock deepsea port*, 31 miles south-southeast of Freeport, Texas; ability to receive tankers to 700,000 DWT, with unloading rates up to 150,000 barrels per hour. Cancellation of the project occurred after excessive licensing restrictions forced participants to withdraw.
- *Enhanced oil production*, Kern County, California. Delays caused by failure of EPA and the California Air Resources Board to issue necessary permits for steam generators in the late 1970's restricted production by nearly 200 MB/D. If additional Clean Air Act restrictions were removed, heavy oil production could increase by 350 MB/D.
- *Georges Bank Marine Sanctuary proposal.* The Conservation Law Foundation nominated the entire Georges Bank fishery as a sanctuary—a total of 20,000 square miles encompassing the North Atlantic OCS Lease Sale area. This nomination was submitted to delay Lease Sale #42 in mid-1979 and to reserve the Georges Bank area. The fishery was placed on the list of areas that could possibly be designated a marine sanctuary.
- *Oil and gas production*, Bastian Bay, Louisiana; 828,000 barrels of oil and 2.9 billion cubic feet of natural gas reserves. A delay of 153 days occurred before the Federal Energy Regulatory Commission granted a permit to build a gas pipeline from an offshore platform.
- *Oil production*, West Hastings Field, Texas; 4 MB/D. Requirements of the Texas Air Control Board and EPA have prevented the use of gas-lift compressors since late 1978.
- *Oil production*, Cat Canyon Field, California. Two steam generators were shut down due to tight natural gas supplies. This resulted in a decrease in the production of crude oil. An application was made to the California Air Pollution Control District for Santa Barbara County requesting permission to use crude oil for fuel. The district would not grant a permit unless the company hired an outside consultant to prepare an EIS. The resultant delay was estimated to be six to eight months.
- *Oil production*, USA #1-a, Perry County, Mississippi. Normal procedures were followed to obtain approval for drilling an exploratory well. After drilling, control problems were encountered and the well had to be abandoned. The company wanted to drill an identical well only 50 feet from the first one. The permitting agency decided that doing so would require repetition of the entire permitting process and completion of another environmental assessment. It is estimated that this requirement delayed the project five months.
- *Offshore oil and gas production*, Block 104, East Cameron, Louisiana. Requests for permits to drill were filed in late 1978, but were not awarded until mid-May 1979.
- *Offshore oil and gas production*, Block 687, Matagorda Island off Texas. An exploration

plan was filed with the appropriate regulatory agencies in April 1978. The company did not obtain approval until January 1979. The delay stemmed primarily from the U.S. Fish and Wildlife Service's concern that boats and helicopters passing through the intercoastal waterway to and from the drilling rig would disturb the winter nesting grounds of whooping cranes located in the Aransas National Wildlife Refuge. It has been demonstrated that this is not the case.

- *Offshore oil and gas production*, Block 912, off Georgia. This tract was purchased at the federal lease sale held March 28, 1978. Requests for permits were sent to the U.S. Army Corps of Engineers on May 26, to EPA on June 12, and to USGS on December 27. The well permit was not granted until May 16, 1979, almost one year after the first requests were submitted.

- *Offshore oil and gas production*, Block 139, South Marsh Island, Gulf of Mexico. This tract was purchased at the federal lease sale held December 19, 1978. Requests for a drilling permit were sent to EPA on February 26, 1979, and to the USGS on March 9. The well permit was received on July 12, 1979, approximately five months after it was requested.

- *Offshore oil and gas production*, Santa Barbara Channel, California. After the 1969 Santa Barbara oil spill, the USGS imposed a moratorium on construction of all additional platforms in the area while it studied the cause of the spill. Installation of Platform Henry was delayed approximately 11 years before the USGS finally approved the third development plant.

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Chapter Three
Other Issues of the 1980's

Environmental issues that the NPC believes may be significant in the 1980's are briefly mentioned in the Executive Summary. There are several other issues whose causes are not clearly defined and that are affected by many factors and industries, of which the petroleum industry is only one. Of concern are: the ecological and public health effects of, and the control strategies for, acid rain; the CO_2 "greenhouse" effect; groundwater contamination; and indoor air pollution. Groundwater contamination is discussed briefly in Chapter Two. The remaining issues and the setting of NAAQS are discussed below.

Acid Rain

The phenomenon of "acid rain" has lately drawn increasing attention because of claims that it is causing environmental damage in the United States and Canada. These claims have been criticized by some as unproven. While there are indications that there have always been occurrences of natural acid rain, there are also indications that man-made pollutants from the combustion of fossil fuels contribute to the acidity of rainfall. These basic disagreements highlight the uncertainties that policy-makers confront as they decide what course of action should be followed to deal with the acid rain issue.[1] Congress recognized these uncertainties when it enacted Title VII of the 1980 Energy Security Act, which authorizes $50 million to be spent over the next 10 years to obtain information on the causes, extent, and effects of acid rain.[2]

Definition of Acid Rain

Acid rain is the common term for the more general phenomenon of acid deposition. Acid deposition includes acidic snow, sleet, fog, and particulate matter as well as acid rain. Pure water saturated with CO_2 yields a pH of 5.6, but both natural processes and man's activities can change it. Acid rain commonly refers to even lower pH values. The acid content of rain is generally about 60 percent sulfuric acid, 30 percent nitric acid, and 10 percent hydrochloric acid. There may be small concentrations of organic acids present. These proportions vary with region and time.

Influences on the Acidity of Rain

The acidity of rainfall is influenced by the amount and kind of gases dissolved in it. These include SO_2, NO_x, hydrogen chloride, and ammonia. Particulate matter may also influence rainfall acidity as well as heavy metals, which can catalyze the formation of stronger acids in rain. All have natural and man-made origins.

There is increasing evidence that SO_2 and NO_x emissions that come primarily from the burning of fossil fuels cause acid rain. One report has suggested that local oil-fired sources (utility, residential, and commercial boilers) may contribute to precipitation acidity because burning oil produces sulfates directly in the boiler, and produces catalytic materials that catalyze the transformation of SO_2 into sulfates in the atmosphere.[3] Oil-fired sources also generate NO_x. To determine whether these beliefs are valid, it is necessary to know the relationship between SO_2 and NO_x emissions and the pH of rain. However, this emissions/pH relationship is very complex and consists of at least six components:

- Amount of SO_2 and NO_x emissions
- Mechanism (especially conversion rates) by which SO_2 and NO_x emissions are converted into sulfates and nitrates
- Atmospheric transport of pollutants, including meteorological factors

- Efficiency with which clouds incorporate pollutants
- What happens within the clouds that affects the acidity of rain
- Changes in the raindrops as they fall through the atmosphere.[4]

Except for the amount of emissions, which is fairly well known for anthropogenic sources, knowledge about the remaining five components is limited.[5] This lack of knowledge prohibits prediction of what effect a given level of SO_2 and NO_x emissions (or emissions reduction) will have on the acidity of rain.

Effects of Acid Rain

There is no consensus among researchers about the types and magnitude of the potential adverse impacts of acid rain. However, acid rain can affect aquatic and terrestrial ecosystems, soils, materials, and structures, and even man (indirectly). Most of the data available to date on impacts of acidic precipitation are derived from studies of the effects of increased acidity on aquatic organisms.[6]

The acidification of Scandinavian lakes has been attributed to acid rain. Lakes with depleted fish populations and disturbed biota have been discovered in the northeastern United States and eastern Canada. It is widely assumed that the condition results from acid rain, but this conclusion has not been proven. For instance, local runoff from bogs, polluted streams, and mine drainage can be acidic, and surrounding bedrock and soils have different capabilities to neutralize acid deposition.[7]

Some observed effects of acidified lakes include uptake of heavy metals by aquatic biota, loss of young fish and other aquatic animals, and elimination of algae and other aquatic plants.[8] However, the acidity of freshwater lakes reflects not only the acidity of precipitation, but also the acidity of local inputs (bogs, polluted streams, mine drainage, and runoff over watershed areas) and the capacity of the bedrock and soils of its watershed to neutralize acid deposition.[9]

The effects of acid rain on vegetation observed in controlled studies have been both detrimental and beneficial. On one hand, injury to leaves and the induction of lesions in crops and trees have been noted; while on the benefit side, stimulation and enhanced growth of crops and trees have been observed. In addition, both inhibition and increased incidence of diseases in certain crops have been noted.[10]

The potential impacts of acid rain on vegetation and soils have been studied in laboratory experiments using simulations of exposure to acid rain. Frequently, the simulated rain has been more acidic than natural rain. According to one report, there has been no visible or detectable damage to terrestrial ecosystems outside the laboratory.[11]

Laboratory studies have shown also that leaching of some soil nutrients is accelerated by increased acidity. Other scientists have shown that soil fertility may be increased by the deposition of nitrates and sulfates (typical components of fertilizer) in acid rain.

Acid deposition is known to corrode metals, building materials, paints, and other surface coatings. This is likely a complex phenomenon enhanced by other pollution processes.[12]

Few studies have been reported on the direct health risks from exposure to acid precipitation. There are claims that, potentially, the increased presence and ingestion of heavy metals in acidified drinking water could represent a health risk.[13] However, reported concentrations of heavy metals in waters analyzed have been orders of magnitude below public health drinking water standards.[14]

Thus, while laboratory studies have shown that potential problems may exist, these studies generally have not been confirmed by field observations. It is difficult to assess the effect of acid precipitation on many ecosystems against a background of differences caused by annual climatic variation. Additional research to determine the true state of effects is needed.

The need for further research was also noted by the Committee on the Atmosphere and Biosphere of the National Research Council (NRC).[15] The NRC published the results of its literature review in October 1981, pointing out that scientific evidence on acid deposition is "incomplete in many respects." However, it "renders a rather unfavorable picture of the consequences of current fossil fuel burning practices." It says that "the picture is disturbing enough to merit prompt tightening of restrictions on atmospheric emissions from fossil fuels...." It further concludes that "atmospheric pollution and its consequences deserve major consideration when the sources and sites of energy production are decided. However, much remains to be done if we are to adequately reassess the ecological significance of atmospheric pollutants generated by different energy systems." The text of the report is a thorough analysis of the effects of acidity on aquatic and terrestrial ecosystems; however, the study is not definitive because critical questions such as atmospheric transport and transformation are not explained in detail.

Trends in Rainfall Acidity

At present, there appears to be no clear evidence that rainfall acidity is increasing. Most of the claims of increasing rainfall acidity are based on maps published by Cogbill and Likens.[16] These maps show pH contours, which are based on calculated pH values. The reported trend toward increasing acidity is controversial, however, because rainfall data were acquired at different sampling stations operated over different time periods and with different sampling methods. Reanalysis of the Cogbill-Likens data by examining trends at the same stations have shown there is no discernible trend in rainfall acidity.[17]

Other studies reach similar conclusions. For example, continuous measurements taken over a 10-year period at a station in Hubbard Brook, New Hampshire, revealed no statistically significant trend in rainfall acidity.[18] The USGS's 13-year monitoring program in New York State also failed to show a significant trend in rainfall acidity.[19]

Acid Rain Controls

It may well be that source correction is the most costly, and possibly the least effective, mitigation strategy. The imposition of more stringent emission limitations on large stationary sources that emit SO_2 and NO_x has been advocated. Although numerous sources emit these pollutants, the proponents of controls have, thus far, focused their concerns on SO_2 emissions from coal-fired power plants.

The present Clean Air Act contains no statutory provisions expressly dealing with acid rain. The EPA recently conducted an analysis of the Act and concluded that any further emission controls on large sources of SO_2 and NO_x were either impractical or legally unsupportable. Hence, the current reauthorization of the Clean Air Act is likely to serve as a forum for discussion of acid rain.

In spite of a lack of explicit authority for EPA to address acid rain, the Clean Air Act and EPA and state regulations presently impose significant and costly emission limitations on coal- and oil-fired boilers, especially power plants. Specifically, these emission limitations include NSPS, BACT, LAER, Reasonably Available Control Technology, and Best Available Retrofit Technology. Other Clean Air Act requirements that serve to limit SO_2 and NO_x emissions include NAAQS, PSD increments (for attainment areas), stack height credit (limiting the use of tall stacks), and "reasonable further progress" requirement (net decline in emissions in nonattainment areas).

Nationally, SO_2 emissions are predicted to decline from 19.4 million tons in 1979 to 18.9 million tons in 1990, and to 18.5 million tons in 2010.[20] Because certain key assumptions underlying these predictions are very conservative (e.g., natural gas will no longer be available by the year 2000), SO_2 emissions may decline even more.

National NO_x emissions in 1977 were attributed to transportation (43 percent of total NO_x emissions), utility fuel combustion (35 percent), industrial fuel combustion (12 percent), and other sources (10 percent).[21] Current DOE projections indicate that NO_x emissions from utilities and industrial sources may rise between 1980 and the year 2000.[22]

Impacts of Control Strategies

The potential acid rain control strategies that EPA examined recently focused on various ways to reduce SO_2 emissions at existing coal-fired power plants, because new plants are already subject to very stringent NSPS for SO_2 and NO_x. Basically, the cost of these control strategies (if EPA were given authority to implement them) could discourage the use of existing coal-fired capacity because of the expense associated with additional SO_2 control. If preliminary assertions concerning the contributions of oil-fired boilers to sulfate levels (and presumably to acid rain) are borne out, additional controls might also be imposed on existing oil-fired boilers, affecting the cost of oil-generated electricity and therefore the demand for oil. In any event, because of the expense of additional controls, the ultimate effect of acid-rain-based controls could be to make electricity more expensive and therefore less competitive with substitute energy sources, such as natural gas. This could reduce the demand for both coal- and oil-fired boiler capacity and increase the demand for substitute energy sources, such as nuclear energy and natural gas.

To the extent that NO_x emissions emerge as a key factor in the acid rain controversy, additional emission reductions could be required for mobile sources. Given the state of the U.S. automotive industry, any such move would be very controversial. The added expense of new motor vehicles could inhibit sales of newer, more efficient models, and thus contribute to a slowing in the anticipated decline in the demand for gasoline.

Finally, the imposition of additional regulations based on acid rain concerns could contribute to the uncertainties facing those industries that operate sources that emit acidic precursors. As the causes and effects of acid rain are not yet well understood, no final

control strategies should be established. In light of the large number of uncertainties surrounding acid rain in both the scientific and policy areas, there is a need for accelerating completion of the 10-year study required by Title VII of the Energy Security Act of 1980.

CO_2 "Greenhouse" Effect

The CO_2 "greenhouse" effect is a postulated global climate change resulting from higher atmospheric CO_2 concentration not yet detected in global temperature measurements. Like acid rain, the problem is universal and not limited to the oil and gas industries. It is based upon the fact that CO_2 in the atmosphere is transparent to ultraviolet rays in sunlight but is opaque to some of the infrared (heat) radiation to which a portion of the sun's ultraviolet light is converted when it strikes the earth. This means that if the CO_2 content of the atmosphere increases, it would tend to prevent the reradiation to space of some of the sun's energy and one of the results could be a change in climate, including an increase in the average global temperature.

Callendar conjectured that the rapid increase in the burning of fossil fuels which has occurred since the start of the Industrial Revolution will result in an increase in the CO_2 concentration in the atmosphere.[23] C. D. Keeling, at Mauna Loa Observatory, Hawaii, initiated in 1958 a program of CO_2 concentration measurement in the atmosphere, which has been essentially continuous ever since.[24] Data from Mauna Loa and three other locations are shown graphically in Figure 13. Seasonal variations, such as rates of photosynthesis and seasonal ocean temperature changes, are apparent and of interest. The relatively close agreement in absolute quantities and the similarity of the trends at each of the sample locations have established a global increase in atmospheric CO_2 as a credible phenomenon.

The coincidence of this increase with the increase in combustion of fossil fuels since about 1860 has led to a widely accepted conclusion that the burning of fossil fuels is a significant, if not the major, contributor to a real increase in atmospheric CO_2. By 1974, the burning of coal accounted for 28 percent of CO_2 production, oil for 35 percent, and natural gas for 19 percent.[25] It is also recognized that agricultural practices such as "slashing and burning" can add to atmospheric CO_2 by both the burning of forest biomass and the concomitant reduction in photosynthetic removal of CO_2.[26] Also, in 1974 the CO_2 released by man-made sources in major areas was: United States, 27 percent; Western Europe, 18 percent; the Soviet Union, 16 percent: other, 39 percent.[27] Therefore, the CO_2 problem, if there is one, will require joint action by major powers, because unilateral action by an individual country or small group of countries will not suffice.

The question as to whether there will be a CO_2 problem has generated considerable debate. The one fact that scientists in this field seem agreed upon is that there has been an increase in global atmospheric CO_2 content from about 315 parts per million volume (ppmv) in 1958 to about 335 ppmv or slightly more today. The cause of this increase is generally attributed to the large quantities of fossil fuel being burned.

The oceans are a very large potential sink for CO_2 and therefore represent a very large unknown. The chemistry of CO_2 absorption in water is well understood and quantified, although there remain questions as to rates and equilibria in sea water. The rates of CO_2 (or carbonate ion) exchange between the atmosphere and surface waters and deeper waters, and the effects of the varying temperatures of ocean waters in different currents and different oceans all are poorly defined as are all of the currents and "turnover" rates, which are of maximum importance in determining the rate of the mixing of additional CO_2 into the oceans.

There have been many good estimates of the total carbon in the biosphere and the rates of exchange due to such processes as photosynthesis and decomposition. There have been several competent attempts to make mathematical models of the system and of its major parts.[28] All of these have added information, but the "area of ignorance" in the total subject remains very large. Madden and Ramanathau have stated that the temperature increase expected to accompany the observed CO_2 concentration increase since the start of the Industrial Revolution should be detectable now, particularly at higher latitudes. The instrumental record does not indicate such a temperature shift.[29] On the other hand, a recent paper by Hansen et al. indicates that indeed the global temperature has risen.[30]

The reason that the subject continues to cause debate and to stimulate research is that it is so very closely tied to the world energy problem. If fossil fuel combustion is the major cause of increasing atmospheric CO_2, if the increasing CO_2 content will result in large or possibly catastrophic climate changes, and if natural constraints are either inadequate or too slow to keep the situation stable, then action must be initiated fairly soon to reduce the discharge of CO_2 into the atmosphere.

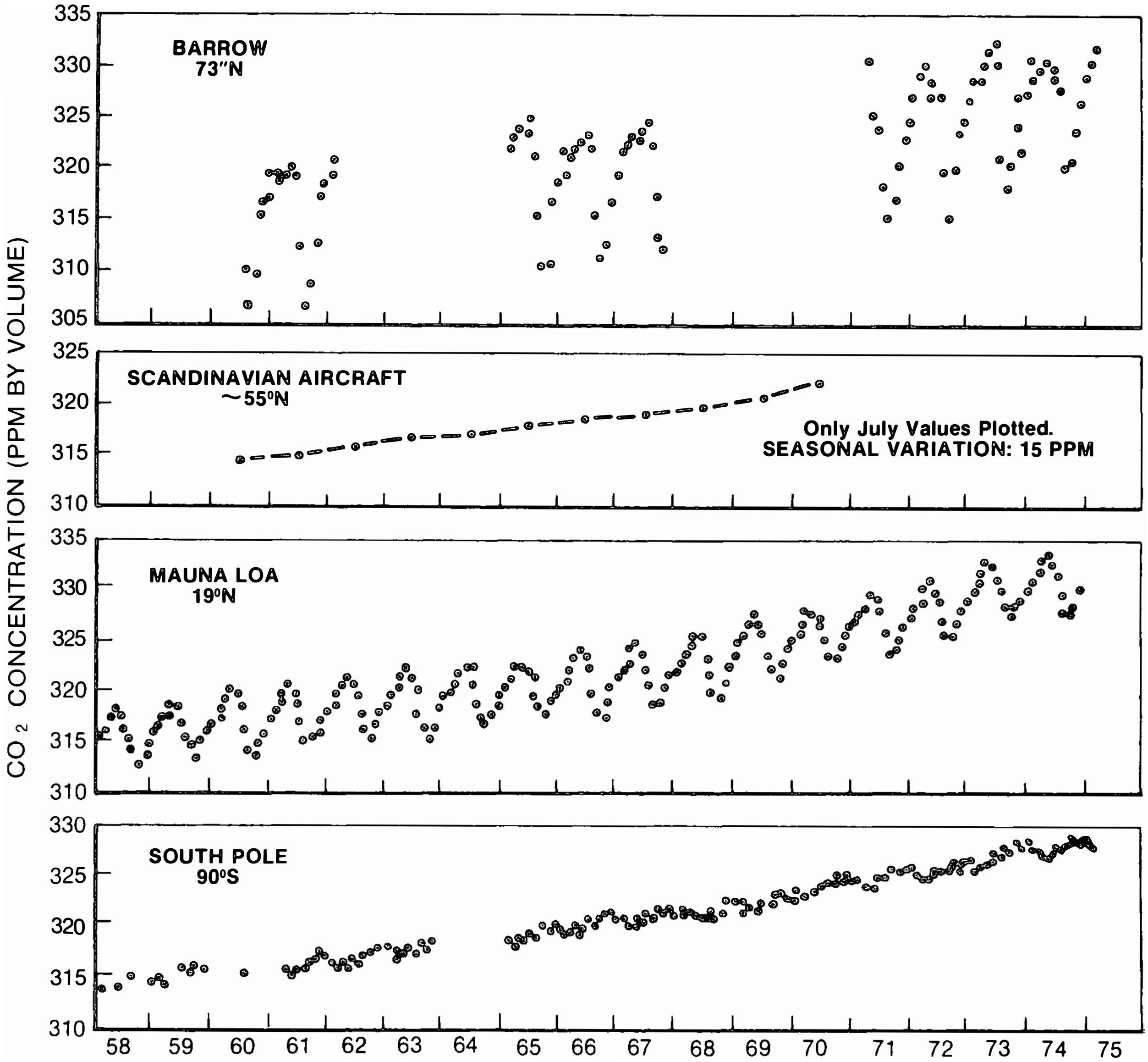

Figure 13. Measurements of CO_2 Concentration in the Atmosphere at Selected Stations.

SOURCE: Machta, L., Hanson, K., and Keeling, C. D., "Atmospheric Carbon Dioxide and Some Interpretations", *The Fate of Fossil Fuel CO_2 in the Oceans,* Plenum Press, 1977.

This action could take the form of restrictions on the use of fossil fuels. The burning of all of the "recoverable resources" of oil (2 trillion barrels) and of gas (9,000 trillion cubic feet) only (not coal) could not raise the global CO_2 level (assuming an airborne fraction of 0.53) to 500 ppmv, which is considered acceptable.[31] The fossil fuels having much greater abundance, particularly coal, are present in sufficient quantity to cause unacceptable CO_2 (and temperature) levels.

Thus the CO_2 "greenhouse" effect may or may not be a serious problem in the future. If it will be a serious problem, plans and implementation strategies should be developed in the near future. The United States and the World Meteorological Organization are commissioning many additional CO_2 monitoring stations to provide a spatially distributed sampling network. Present meteorological stations should provide the necessary notice of a warming trend as soon as it can be differentiated from "normal" temperature fluctuations. The ability to differentiate must be developed. In the meantime, recognizing the immensity of the energy supply industry and the time required to make fundamental changes in such supply areas as raw material source, and recognizing that any mandated restrictions on fossil fuel use would no doubt require such fundamental changes, the petroleum industry must stay closely aware of progress in this field.

Indoor Air Pollution

This issue is now receiving increased attention and may be a major issue in the 1980's. It is a general concern that is broader than the petroleum industry. The issue is concerned primarily with those indoor contaminants that are generated or liberated indoors. When they reach high concentrations they may cause nuisances, irritation of sensitive tissues, illness, and in some cases death from acute as well as chronic exposures.

Most people spend on the order of 80-90 percent of their time in a house, an office, a factory, a store, or a public place such as a theater or a restaurant. There is an increasing amount of scientific data that show that indoor exposure to the criteria and other pollutants could be substantial, but there is little epidemiological evidence on the health effects of the indoor pollutants. Indoor exposure has been largely overlooked in research on the health effects of the environmental criteria pollutants even though it is now being recognized to be an important aspect of the total exposure to many pollutants.

Indoor air pollution in residences, public buildings, and offices is created for the most part by the people's activities and their use of appliances, power equipment, and household materials and chemicals; by wear and tear and deterioration of some of the structural and decorative materials; by thermal effects; and by the intrusion of outdoor ambient air pollutants. In some cases these criteria pollutants may represent the most important stress on human health and welfare and there is an increasing amount of scientific data available to establish their effects and establish standards.

Some of the pollutant sources (e.g., cigarette smoking) have been recognized for a long time, but their importance has only recently been evaluated. A number of sources are of concern only in the indoor environment; i.e., cooking, use of chemical consumer products, space heating devices, and floor and wall coverings. The expanded use of wood and coal for space heating along with kerosine and bottled gas, and use of products that liberate organic substances are a potential contribution to the contamination of indoor air space. In isolated cases, infectious microbes and allergenic agents can grow and contribute to the indoor problem.

A recent report by the Committee on Indoor Pollutants of the NRC has identified a number of specific pollutants and classes of pollutants as current or possible indoor pollutant problems.[32] These are:

- Radon
- Formaldehyde
- Asbestos
- Synthetic fibers
- Tobacco smoke
- Products of combustion
- Microorganisms and allergens
- Moisture.

Ventilation alone may not be sufficient to dilute indoor pollution to an acceptable level and may be inappropriate for a variety of reasons; i.e., not available, not controllable, substantial energy penalties, and introduction of outside pollutants. The introduction of energy conservation systems to reduce ventilation could aggravate problems in indoor air quality, create new problems (nuisances), and perhaps be generally detrimental to health and welfare unless pollultion control measures are taken.

There is no question that there is a great complexity to the study of human exposures that have multiple sources. The barriers between inside and outside air are not absolute, and ambient air contributes to indoor air. Outdoor and indoor air may react chemically to produce a different indoor effect. The development of effective and efficient control strategies for mitigating these suspected indoor problems requires a greatly improved understanding of the exposure levels, the human responses to the exposure, and pollutant interactions.

National Ambient Air Quality Standards

During the 1970's, when the NAAQS were first established and in some cases revised, a great deal was learned about air pollution causes and effects. Improvements are needed in the way the NAAQS are established.

The NAAQS should be reviewed and revised both to reflect sound, up to date scientific evidence and to provide a balance with other important national goals. In other words, the NAAQS must be based on sound medical and scientific evidence and must protect the public health and welfare with an adequate margin of safety. These standards should also take into account the important national goals of producing sufficient energy and maintaining a sound economy.

Some changes in standard setting that EPA could consider are:

- "Primary standards" are set at levels that protect the public health, plus a margin of

safety. When setting that margin of safety, EPA should consider other relevant factors, such as attainability and incremental costs and benefits.

- Define adverse health effects and establish an acceptable methodology for evaluating health risks. EPA's criteria documents and policy analysis documents should evaluate the studies that are used as a basis for deciding a pollutant's health effects. Moreover, EPA should recognize the importance of studies whose findings are supported in other studies. A qualified scientific body, the CASAC of the EPA Science Advisory Board, should evaluate the studies used in EPA's criteria documents as well as the end product; i.e., the NAAQS. Before establishing a new or revising an old standard, EPA should be required to reconcile its findings with those of the scientific body reviewing these findings.
- Make sure that proposed NAAQS and exceedances of the NAAQS allow for the uncertainty in such factors as unique meteorological conditions, air quality monitoring, and air quality computer modeling. Proposed NAAQS should allow more flexibility in determining exceedances (instances when the specified air quality limit is exceeded), and take into account natural occurrences and emergency pollution episodes.
- Analyze additional costs and benefits and take regional differences into account in setting the secondary standards, those standards that are intended to protect property, plants, aesthetics, and other public welfare values.

The issue of how to set and attain the NAAQS, both primary and secondary, will be a major issue of the 1980's. The debate is just now heating up and will probably continue for some time until the NAAQS are revised and in place. As more knowledge is obtained, it is conceivable that this issue will periodically be raised and debated far into the forseeable future.

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Appendices

Appendix A

THE SECRETARY OF ENERGY
WASHINGTON, D.C. 20585

April 9, 1980

Mr. C. H. Murphy, Jr.
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Murphy:

In 1971, at the request of the Secretary of the Interior, the National Petroleum Council published a study report entitled Environmental Conservation. This report dealt with the environmental effects of the petroleum industry and has been of great assistance to Government officials making policy decisions involving pollution control regulations.

During the past decade, extensive new statutory and regulatory frameworks have been established in regard to environmental requirements affecting oil and gas operations. Additionally, significant technological advances in the oil and gas industry have occurred since 1971. These advances not only increase economic efficiency but mitigate environmental hazards as well.

I request that the National Petroleum Council undertake to update the 1971 report on Environmental Conservation. In this update, special emphasis should be placed on determining the environmental problems that are most serious and the impact of current environmental control regulations on the availability and cost of petroleum products and natural gas.

For purposes of this study, I will designate R. Dobie Langenkamp, the Deputy Assistant Secretary for Resource Development and Operations, Resource Applications, to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

C W Duncan Jr

Charles W. Duncan, Jr.

Background Information on the National Petroleum Council

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- *Environmental Conservation—The Oil and Gas Industries* (1971, 1972)
- *U.S. Energy Outlook* (1971, 1972)
- *Potential for Energy Conservation in the United States: 1974-1978* (1974)
- *Potential for Energy Conservation in the United States: 1979-1985* (1975)
- *Ocean Petroleum Resources* (1975)
- *Petroleum Storage for National Security* (1975)
- *Enhanced Oil Recovery* (1976)
- *Materials and Manpower Requirements* (1974, 1979)
- *Petroleum Storage & Transportation Capacities* (1974, 1979)
- *Refinery Flexibility* (1979, 1980)
- *Unconventional Gas Sources* (1980)
- *Emergency Preparedness for Interruption of Petroleum Imports into the United States* (1981)
- *U.S. Arctic Oil and Gas (1981)*

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

National Petroleum Council Membership 1981

ABERNATHY, Jack H.
Vice Chairman
Entex, Inc.

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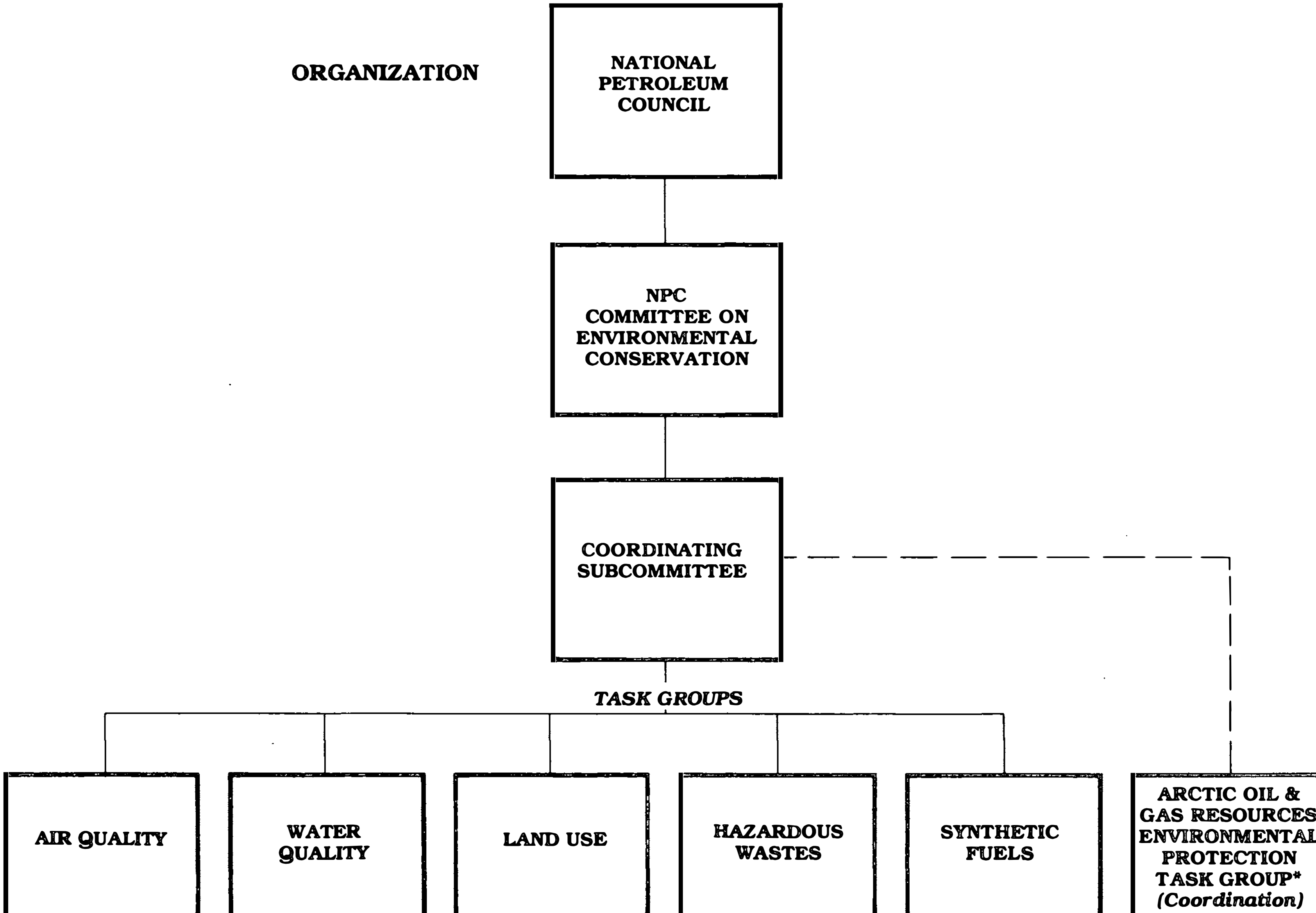

****Reports to Coordinating Subcommittee, NPC Committee on Arctic Oil and Gas Resources***

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Appendix C

Environmental and Resource Conservation Laws Enacted by Congress, 1970-1980

1970—National Environmental Policy Act
- Clean Air Act Amendments
- Water Quality Improvement Act
- Water Bank Act

1971—Alaska Native Claims Settlement Act

1972—Federal Water Pollution Control Act Amendments
- Coastal Zone Management Act
- Environmental Pesticide Control Act
- Noise Control Act
- Marine Mammal Protection Act
- Marine Protection Research and Sanctuaries Act
- Ports and Waterways Safety Act

1973—Endangered Species Act

1974—Safe Drinking Water Act
- Energy Supply and Environmental Coordination Act
- Energy Reorganization Act
- Deepwater Port Act
- Water Resources Development Act
- Forest and Rangeland Renewable Resources Planning Act
- Eastern Wilderness Areas Act

1975—Energy Policy and Conservation Act

1976—Federal Land Policy and Management Act
- National Forest Management Act
- Toxic Substances Control Act
- Energy Conservation and Production Act
- Coal Leasing Act Amendments
- Resource Conservation and Recovery Act
- Fishery Conservation and Management Act
- Land and Water Conservation Fund Act Amendments

1977—Surface Mining Control and Reclamation Act
- Clean Air Act Amendments
- Federal Water Pollution Control Act Amendments (Clean Water Act)
- Soil and Water Resources Conservation Act

1978—Outer Continental Shelf Lands Act Amendments
- Endangered Species Act Amendments
- National Parks and Recreation Act
- Clean Water Act Amendments

1979—Emergency Energy Conservation Act
- Safe Drinking Water Act Amendments
- Water Bank Act Amendments

1980—Alaska National Interest Lands Conservation Act
- Comprehensive Environmental Response, Compensation and Liability Act of 1980
- Solid Wastes Disposal Act Amendments
- Used Oil Recycling Act of 1980

Appendix D

Summary of Comments on *Synthetic Fuels and the Environment*

Introduction

In preparing this update of the 1971 National Petroleum Council (NPC) report, the NPC recognized the importance of including synthetic fuels, which were not discussed in the previous report. However, the NPC also recognized that, as the synthetic fuels industry is just entering the commercialization stage, an overall assessment of this rapidly changing industry could not be accomplished within the same amount of time as an assessment of the mature conventional petroleum industry. The NPC chose instead to evaluate the existing literature on the subject and to offer recommendations for improvement of any future studies on this subject that may be undertaken.

The NPC's analysis is based on a review and assessment of the assumptions, methodology, and conclusions of the June 1980 U.S. Department of Energy (DOE) report entitled *Synthetic Fuels and the Environment*, a recent, comprehensive report evaluating the environmental concerns associated with synthetic fuels development. While an extensive literature search was conducted and other reports were examined, none were found to have the depth and wide coverage of the DOE report. The NPC recognizes that any report on a rapidly developing industry is quickly rendered out of date by changes in technology, regulations, and other factors. The Council believes, however, that a review and assessment of the DOE effort can identify areas of improvement in organization, data collection, and analysis that may be helpful in future assessments.

Summary and Conclusions

The Council determined that, in general, the DOE report, *Synthetic Fuels and the Environment*, presents a useful, objective analysis of the impact of synthetic fuels development upon the environment, and the concurrent impact of environmental regulations on the rate and extent of industry development. However, in light of the rapidly evolving technologies and changes in legislative and regulatory controls, there is no doubt that the DOE report is dated. In addition, certain subjects were insufficiently covered in the DOE report, including:

- The role of state and local governments
- Environmental research conducted by industrial laboratories
- The comparative environmental impacts of synthetic fuels relative to the conventional petroleum industry and other industries
- Human health concerns and protective measures.

With respect to broad issues raised by the DOE report, the NPC concluded that:

- All synthetic fuels development is improperly divided into two time frames: research and development from 1980 to 1985, and commercialization from 1985 to 1990. In fact, the timetable will vary widely among the various synthetic fuel technologies.
- The report correctly states that first generation plants require close environmental scrutiny. However, the knowledge gained from these plants should be used not only to assure the adequacy of environmental controls, but also to avoid unnecessarily severe controls.
- The DOE report states that new major regulatory constraints are unlikely to emerge. While this may be true, the DOE report overlooks the cumulative effect of numerous small, site-specific constraints, which cause lengthy delays. The Council

believes that the DOE report estimates of 24 to 36 months for permit acquisitions are overly optimistic. The NPC believes that 24 to 48 months is more realistic.

- The DOE report implies that smaller plants are more advantageous than larger scale plants. This is not necessarily true. There will be many cases where large plants offer cost and environmental control advantages over small plants.

With respect to specific technologies, the NPC found the following principal areas of disagreement:

- In the case of oil shale, the DOE report improperly groups the various techniques together, although each of the mining and process options has unique environmental impact characteristics. The section on the disposal of spent shale does not adequately acknowledge the amount of research conducted on this subject nor the current state of knowledge. The DOE report also indicates that zero wastewater discharge will be generally practical. Although it will be practical in some instances, practices will vary as a function of the process and the meteorology of the location.
- In discussing coal conversion, the DOE report again improperly groups disparate technologies. Coal gasification and associated indirect liquefaction processes differ greatly from direct coal liquefaction.
- The DOE report places undue emphasis on alcohols derived from biomass and urban waste conversion. The future production of alcohols from these processes could be dwarfed by the amount of alcohols and alcohol-derived fuels manufactured by coal gasification, which deserve greater attention. The environmental impacts of biomass and urban waste conversion are also dissimilar and should be treated separately.

The following comments on the DOE report involve environmental issues common to all synfuel technologies:

- Worker safety and health problems have been studied far more extensively than is indicated in the DOE report. Many problems have already been encountered in other industries and their experiences and control technologies may also be appropriate to the synfuels industry. Problems unique to the synthetic fuels industry are being carefully investigated by industry, government, and other groups, notably the National Institute of Occupational Safety and Health.
- Although the report recognizes the importance of socio-economic questions, it fails to recognize the efforts made by industry to alleviate socio-economic impacts of development.
- The DOE report attempted a comprehensive, regional analysis of all factors affecting site selection. Although it provides a useful insight into the complex problems involved, it projects an unwarranted degree of precision. Too many uncertainties exist to allow meaningful conclusions to be drawn, especially in the area of air impact analysis where no generally acceptable models exist.
- Standard setting for synfuels facilities is a sensitive issue. The standards for first-generation plants will be set on a case-by-case basis. For these plants, standards should be comparable to analogous new sources. Where nonconventional contaminants are encountered, suitable control requirements should be imposed.
- The DOE report correctly states that biological monitoring and health effects testing will be necessary for synthetic fuel development. However, the large amount of such work already completed or under way is not recognized. In addition, the mitigating effects of product upgrading processing on toxicity are not mentioned in the DOE report.

While the need for additional reports at this time is questioned, the NPC recommends that, should additional reports be undertaken, the scope of the analyses be brief, issue oriented, or site specific, rather than all-inclusive. Separate analyses would avoid the treatment of dissimilar problems as equally critical, and a clearer knowledge would be gained of the particular needs of each technology.

Improved data sources now exist, many of them site and/or process specific. These sources include private research, permit applications, monitoring information, and government reports. Utilizing available site-specific data is recommended as it was observed that many, if not all, of the impacts of synfuels development will be felt primarily in the state and local communities where the facilities are located. Attempts to accommodate the communities involved result in differing permitting times and conditions, levels of public acceptance, types of environmental controls needed, and socio-economic impacts.

Appendix E

Executive Summary

U.S. Arctic Oil and Gas

(This appendix was reprinted in its entirety
from the 1981 National Petroleum Council report, *U.S. Arctic Oil and Gas.*)

PREFACE

On April 9, 1980, the National Petroleum Council (NPC), a federal advisory committee to the Secretary of Energy, was requested by the Secretary to undertake a comprehensive study of Arctic area oil and gas development.

In requesting the study, the Secretary of Energy specified that:

> . . .the study should include: resource assessment information; an engineering economic analysis for exploration, development, and production activities; a state-of-the-art presentation on the adequacy of available recovery technology and prospects for innovative technology required by the harsh Arctic climate; an assessment of the environmental impact of Arctic oil and gas operations and of the available mitigating measures; a comprehensive review of the adequacy of the existing oil and gas transportation infrastructure and proposals for improving this situation; and a discussion of any international jurisdictional questions that may affect Arctic area development.

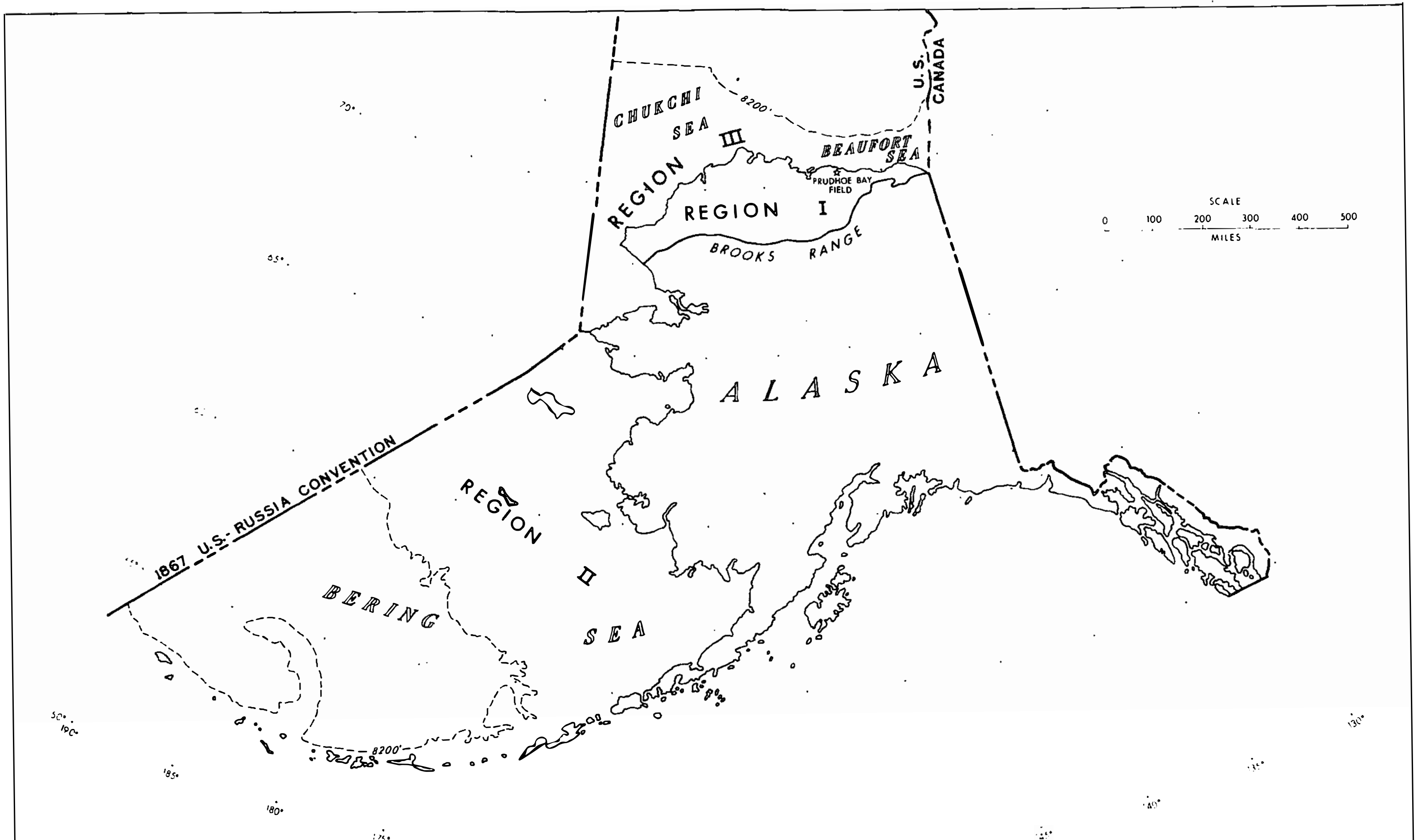
The complete text of the Secretary's request letter and a description of the National Petroleum Council are provided in Appendix A.

To assist in its response to the Secretary's request, the NPC established the Committee on Arctic Oil and Gas Resources under the chairmanship of Robert O. Anderson, Chairman of the Board, Atlantic Richfield Company. Hon. Jan W. Mares, Assistant Secretary for Fossil Energy, U.S. Department of Energy, served as Government Cochairman of the Committee. The Committee established a Coordinating Subcommittee and seven Task Groups to provide coordination and technical advice for the Committee. Rosters of these study groups are included in Appendix B. The broad membership of these groups includes representatives of both major and independent petroleum-related companies; federal, state, and local governments; the academic community; the environmental movement; organized labor; consultants; and Alaskan native organizations. As might be expected with such a diverse membership, all participants do not necessarily endorse each finding and recommendation; however, this report represents a consensus of the participants' views.

Geographic Area of the U.S. Arctic

In discussions with representatives of the U.S. Department of Energy during the early stages of this study, the Arctic area referenced in the Secretary's request letter was defined as seabed and subsoil under the resource jurisdiction of the United States north of the Aleutian Islands offshore and land territory north of the Brooks Range onshore. Accordingly, the terms "U.S. Arctic" and "Alaskan Arctic" as used in this report include the Bering Sea, a sub-Arctic region.

Due to differences in physical environment, operational requirements, and industry's expertise in the Arctic, three geographic regions, as shown in Figure 1, were defined for the purposes of this study.



NOTE: The United States has not fully resolved its Continental Shelf boundaries with other states concerned. The lines on this map are for purposes of illustration only and do not necessarily reflect the positions or views of the United States with respect to the boundaries involved.

Figure 1. Regions Studied.

Region I, onshore Alaska north of the Brooks Range, is composed of the coastal plains and the foothills of the Brooks Range. Region II, the Bering Sea, includes a broad continental shelf less than 650 feet (200 meters) in water depth; however, the southwest portion of the region falls off rapidly to extreme water depths. This region is characterized by seasonal ice and severe storms. Region III, the offshore area north of the Bering Strait, includes the Beaufort and Chukchi Seas. This region also has a continental shelf that falls off gradually to 650 feet in depth and more rapidly to greater depths. The majority of this region is characterized by multi-year ice with ice ridges that may reach a thickness of 150 feet (45 meters), although the area very near the coast may be ice free for as much as three months a year.

Task Groups

Seven Task Groups were established to provide specialized expertise for the development of this report. Experts in the areas of jurisdictional issues, resource assessment, exploration, production, transportation, environmental protection, and economics provided the data and support for this report.

The Jurisdictional Issues Task Group defined, for the purposes of this report, the territorial and seabed and subsoil limits of the United States in the Arctic area, applying principles embodied in international agreements and in the Draft Convention on the Law of the Sea. The Task Group also identified areas of state/federal dispute, native claims, and land withdrawal that may affect oil and gas operations in the Arctic.

The Resource Assessment Task Group made estimates of the conventionally recoverable undiscovered oil and gas resources in the Arctic, utilizing the expert opinions of 17 organizations or individuals that responded anonymously to the NPC Assessment of Arctic Oil and Gas Potential questionnaire. An independent public accounting firm aggregated the survey results for 20 geologic, geographic, or jurisdictional areas. Using Monte Carlo techniques, the Task Group provided resource assessments for the total Arctic area and the three regions previously described.

Petroleum operations in the Arctic were examined by three Task Groups: Exploration, Production, and Transportation. Each of these Task Groups developed a comprehensive review of all factors related to Arctic operations, especially the limitations of conventional methods and the opportunities for the development of innovative techniques to be used in the Arctic. These Task Groups also developed cost data on Arctic operations and examined the effect of the Arctic environment on the timely development of oil and gas resources.

The Economics Task Group utilized the output from the other Task Groups to determine the economic attractiveness of selected areas and to calculate their economically attainable resources. In addition, the sensitivity of these results to changes in key parameters such as timing were evaluated, and total capital requirements were estimated.

The Environmental Protection Task Group examined the physical and biological environment in which petroleum operations may occur, noted the effect these operations may have upon the environment, examined the risk avoidance and mitigation techniques that can be employed to protect the Arctic environment, and identified environmental data needs. In addition, the impact of operations upon Alaskan native populations as well as legislative and regulatory constraints to oil and gas development were studied.

The work of these seven Task Groups is the basis for this report and many of their findings have been incorporated into it. The working papers submitted by the individual Task Groups for the use of the Coordinating Subcommittee are available from the office of the National Petroleum Council. A listing and abstracts of these working papers are presented in Appendix G.

Findings and Recommendations

Findings

It is the Council's judgment that oil and gas production from undeveloped areas in the U.S. Arctic could make a significant contribution to the nation's future energy supply. This judgment is based on the analyses set forth in this report and on the expertise of the study participants, and is supported by the following findings:

- ***Substantial undiscovered oil and gas resources are believed to exist in the Arctic regions of the United States.*** The total potentially recoverable undiscovered oil and gas resources in the U.S. Arctic are estimated to be approximately 24 billion barrels of oil and 109 trillion cubic feet of total gas, or a total of 44 billion barrels of oil and oil-equivalent gas. It is also estimated that there is a 1 percent probability that the total undiscovered recoverable resources in this area could exceed 99 billion barrels of oil and oil-equivalent gas; there is an estimated 99 percent probability that the total undiscovered recoverable resources will exceed approximately 13 billion barrels of oil and oil-equivalent gas. These resources constitute a significant portion of total U.S. undiscovered oil and gas. It is felt that the Arctic Slope and the Bering, Beaufort, and Chukchi Seas all contain basins with significant promise.

- ***The basic technology is available to safely explore for, produce, and transport oil and gas in most of the U.S. Arctic.*** Industry experience in the North Slope area, Cook Inlet, Gulf of Alaska, Canadian Arctic, North Sea, and in other cold, hazardous, or deep-water areas provides the basis for the design, construction, and operation of systems in Arctic regions. Proven technology exists for onshore operations. Proven technology and sufficient information and technical expertise for advanced design work is available for the industry to proceed confidently with operations in water as deep as 650 feet in the southern Bering Sea and to about 200 feet in the more severely ice-covered areas of the northern Bering, Chukchi, and Beaufort Seas. These capabilities will allow development of prospective areas in all of the northern Bering Sea, most of the southern Bering Sea, and well out into the ice-covered areas of the Chukchi and Beaufort Seas.

- ***Long lead times are required prior to production in the Arctic because of its harsh climate, remote location, and the large scale of the projects.*** Depending on the location, at least 9 to 14 years will be required for planning, permitting, exploration, development drilling, design work, facility construction, and transportation system construction. These timing projections are felt to be near the minimums under improved business and regulatory conditions; even in an emergency, development could be accelerated by only a few years because of the unalterable physical obstacles.

- ***Economic analyses indicate that it will be attractive for industry to develop U.S. Arctic oil and gas if sufficiently large resources are found to support the costly development, production, and transportation systems that are***

required to operate in the region. Oil and gas operations in the hostile environment of the remote Arctic regions will be much more costly than those experienced in other climates. A significant cost associated with developing large resource volumes will be the major new transportation systems, either marine or pipeline, required to move the oil and gas to the market. Based on the assumptions used in these analyses, it appears that 18 to 21 billion barrels of the 24 billion barrels of potentially recoverable undiscovered oil will be economically recoverable. Of the 109 trillion cubic feet (TCF) of potentially recoverable natural gas and natural gas liquids, 68 TCF is non-associated and 41 TCF is associated, i.e., produced with oil from the same reservoir. Under the assumptions used in these analyses, 10 TCF of non-associated gas will be economically recoverable. At a 10 percent rate of return criterion, more than 22 billion barrels of oil and oil-equivalent gas are estimated to be economic. Certain key assumptions made and bases established in these economic analyses must be kept in mind in interpreting the economic findings since they have significant effects on the analyses and could yield low-side estimates. In this study, the more complex economics of associated gas were not evaluated, nor were the economics of the incremental use of the Trans-Alaska Pipeline System or the proposed Alaska Natural Gas Transportation System considered. The volume of economically recoverable gas would likely increase substantially if existing or planned production and/or transportation systems are in place and available at the time of development, since the analyses assume grass roots investments are required for all oil and gas production and transportation.

Some individual companies, utilizing their own internal assumptions and assessments, have considerably more optimistic estimates of economically recoverable gas. An optional portion of the NPC resource assessment survey requested participant estimates of the economically attainable resources. Limited responses suggest that 14 billion barrels of oil, 34 TCF of non-associated gas, and 20 TCF of associated gas, or a total of 24 billion barrels of oil and oil-equivalent gas, would be economically recoverable. This total is very similar to that obtained by the detailed analyses in this report.

- ***Pre-exploratory resource assessment or economic analysis, while useful, should not be given undue weight in the decision to open a basin for leasing.*** Until a considerable amount of exploratory drilling is conducted in each and every basin, any assessment of potential resources or economically recoverable resources and whether the resources will be oil and/or gas must be taken as a preliminary estimate.
- ***Several promising sedimentary basins extend across international boundaries both to the east and to the west.*** The boundary with the Soviet Union is defined by the Convention of 1867; no agreement exists as to the continental shelf boundary with Canada. No promising areas were identified beyond the seabed and subsoil under the resource jurisdiction of the United States as they are defined by the Draft Convention on the Law of the Sea.
- ***Year-round oil and liquefied natural gas tanker operations to ports south of the Bering Strait are feasible and practical.*** In severe ice areas north of the Bering Strait, year-round tanker operations can probably be established, but the ability to maintain a continuous uninterrupted schedule is uncertain. Significant interruptions of tanker arrivals would require additional facilities if continuous production from a field is to be maintained. The cost of these facilities or the loss of revenues resulting from production cutbacks would reduce the amount of economically recoverable oil and gas in marginal areas.
- ***Many benefits can accrue to Alaskans from the oil industry's activities in their state.*** Some of the income from lease sales, royalties, and taxes will provide additional support for government programs. Industry operations have provided employment, a source for emergency medical aid, and communications. Industry personnel and equipment have been used for rescue operations, and company personnel are usually active in their local communities.

- ***Native interests exert an important influence over oil and gas development in the Arctic.*** Through their native-owned corporations, Alaskan natives control more than 40 million acres of land throughout Alaska that they wish to see developed in a manner that will meet their social and financial goals. Subsistence activities, particularly hunting and fishing, are of vital importance in preserving their cultural heritage and integrity. The oil and gas industry must be responsive to these interests.
- ***Impacts from oil and gas development on the lifestyle of the Alaskan native population can be anticipated, managed, and made beneficial by improvements in communication among all parties involved and by careful long-term joint planning.*** It is in both the communities' and industry's best interests to develop good practical planning capabilities in order to prepare for future petroleum developments. Such planning is necessary to help alleviate citizen concern about their lifestyle and livelihood and to maximize opportunities for these citizens resulting from the development activities while avoiding adverse impacts.
- ***The Arctic environment is important and sensitive, but impacts from the development of oil and gas resources can be minimized or avoided.*** The ecology in this region, both onshore and offshore, is important. Although accelerated activities in undeveloped areas will require an extension of existing information and technology, no problems are perceived that are beyond the demonstrated capability of the industry to solve. Prudent designs and methods of operation will allow oil and gas development to co-exist with commercial fisheries, recreational activities, and subsistence needs that are dependent on biological resources.
- ***A complicated regulatory system created by federal, state, and local governments to control oil and gas activities has delayed and added to the cost of Arctic oil and gas development.*** This system is made more complex by overlapping jurisdictions, by limited coordination between agencies, and by the lack of a clear federal policy regarding Arctic development. There appears to be unanimous agreement by all affected parties that this regulatory system needs to be redesigned.

Recommendations

To assist the nation in realizing the oil and gas potential of the U.S. Arctic, the federal government should implement and maintain a clear, comprehensive policy for Arctic oil and gas development. This policy should be responsive to the national need for domestic resources, consistent with national energy policies. Expedited development of oil and gas resources and multiple use of Arctic lands, both onshore and offshore, should be an integral part of this policy, consistent with local needs and concerns. State and local governments should be encouraged to support this policy. Accordingly, the Council makes the following specific recommendations:

- ***A stable lease schedule offering federal Arctic lands for private exploration and development should be established, with all areas both onshore and offshore having oil and gas potential included in the schedule.*** Areas with the greatest potential should be scheduled for early leasing. Scheduled lease sales need not be delayed until comprehensive information on physical and biological environmental conditions is available, or until specific site information is available; such information can be developed well in advance of any significant onsite work. Adequate provisions exist under present law to allow withholdings of tracts with potentially significant environmental problems until mitigating measures are developed.
- ***The leasing system should be made responsive to the unique conditions encountered in the development of oil and gas in the U.S. Arctic.*** Each lease sale should include a sufficient amount of acreage to justify necessary operating systems. Acreage offered for the first sale in a frontier area should cover all major exploration prospect features in the entire basin or area of interest so as to expedite the evaluation of prospective areas. The primary lease term for Outer Continental

Shelf leases should be at least 10 years because remote operating areas combined with hostile climate require lengthy lead time preparations. An automatic "suspension of production" provision should become a part of leasing policy so that marginal discovered resources can be retained by the lease owner until economic transportation can be justified.

- ***A comprehensive exploratory drilling effort extending to all areas thought to have undiscovered resources should be undertaken by industry to define the true oil and gas potential of the U.S. Arctic***. Several resource assessments of the type prepared for this report have been completed by others. Additional similar analyses will not enhance real knowledge of the region's resources until the promising areas have been leased and tested by drilling, and important new data have been obtained.
- ***A specific existing agency should be designated the responsibility for expediting permitting actions in the Arctic***. A common procedure should be established to ensure that both its own permits and those of other involved agencies are expedited. The most important way to accelerate and improve efficiency is to streamline and simplify the laws and regulatory processes relating to leasing and permitting. Overlapping responsibilities of regulatory agencies should be eliminated. Such changes would allow government to be more pragmatic in its decision making. Statutes and procedures that unnecessarily delay operations or are not applicable to the Arctic should be modified or eliminated. Deadlines should be set for procedural requirements and for approvals. Such initiatives should be aimed at expediting energy development while fully responding to substantive environmental and socio-economic needs.
- ***Government agencies with legislated responsibilities for conducting operations in support of exploration, production, and transportation activities in the Arctic should be organized and staffed to meet in a timely manner those responsibilities***. Some of these responsibilities include search and rescue, oil spill surveillance, weather and ice forecasting, structure accreditation, vessel inspection, preparation of environmental impact statements, and surface and air navigational aids.
- ***Continued private and public Arctic research is important to the national interest and should be encouraged and supported where necessary***. Research and development in Arctic technology for operations in hostile environments will lead to evolutionary improvements in operating systems. Efforts to enhance knowledge of ice conditions, ice properties, and ice forces should be stressed. Biological research and monitoring should be continued. Federally funded research programs should focus on collection and characterization of fundamental data and testing programs of broad issue. Timely and rapid dissemination of information obtained by government agencies should be required.
- ***The federal and state governments should provide necessary assistance to local communities and governments in understanding and planning for the community development that will evolve with oil and gas development***. Particular attention should be given to determining the most efficient means of funding comprehensive and continuous planning efforts.
- ***Sources of funding should be identified for government and community programs and activities related to development of oil and gas in the U.S. Arctic.*** Both lease sales and production royalties provide substantial sources of funds directly attributable to oil and gas industry activities. A portion of these direct revenues could be used to ensure that appropriate governmental support is provided. Stability of funding is required for effective execution of these programs.

More detailed findings and recommendations can be found in the chapters of this report.

Summary

History

Arctic oil and gas exploration began in Alaska with the U.S. Geological Survey's (USGS) surface work in 1901. In 1904, oil seeps were found on what is now the National Petroleum Reserve-Alaska (NPRA). This 23.6-million-acre area was designated the Naval Petroleum Reserve Number 4 (NPR-4) by Executive Order in 1923, and some geological mapping occurred shortly thereafter. From 1944 until 1953, the Navy, in conjunction with civilian drilling contractors, conducted an extensive geological mapping and exploratory drilling program on the NPR-4. Renewed government exploration in the NPRA was undertaken in the 1970s. Commercial quantities of oil and gas were not found.

During 1949 and 1950, in an effort to develop a natural gas fuel supply for the Navy's Barrow Camp, several test wells were drilled in the vicinity. These South Barrow wells were the first development wells drilled and completed in the U.S. Arctic. They furnished proof that hydrocarbons could be produced in the Arctic region.

In 1968, the Prudhoe Bay oil field was discovered east of the NPRA. After this field was discovered, two alternate transportation options were considered: tanker movement through the Northwest Passage, and pipelining across Alaska to an ice-free port. The pipeline option was chosen on the basis of reliability, and pipe was ordered. The design called for a 48-inch-diameter line with a potential capacity of 2 million barrels per day, initially equipped to deliver 1.2 million barrels per day across an 800-mile route from Prudhoe Bay to an ice-free terminal in Valdez, Alaska.

Opposition to the pipeline by environmentalists and disputes over land ownership led to a series of legislative, environmental, and judicial hearings that delayed the start of construction for five years. Construction of the Trans-Alaska Pipeline System (TAPS) began in April 1974, and the pipeline was completed and went into service in mid-1977. Upon completion of TAPS, the field was placed on continuous production.

During the early 1970s an extensive research and development program was carried out by industry to solve the many problems associated with oil operations in the Arctic. The success of these programs is attested to by the fact that some 350 wells have been completed, and oil is being produced and transported at a rate of 1.5 million barrels per day. A total of approximately 2 billion barrels of oil have been moved to market as of the end of 1981. A second, smaller field, Kuparuk, is now being developed, and production is expected to commence in 1982.

Development of the Prudhoe Bay field and construction of TAPS and the Valdez terminal were conducted under the most rigorous design and quality control specifications ever imposed upon onshore petroleum operations. Successful operation of this system has been achieved and it represents a model for future land pipelines and terminals.

Resources

An evaluation of the potential oil and gas resources in the sedimentary basins of the U.S. Arctic was made based on a review of published information, USGS data, and a survey of the study participants. It was established that as of August 1980, 16.5 billion barrels of recoverable oil and oil-equivalent gas had been discovered on the North Slope of Alaska. Of this total, 10.2 billion barrels are oil and 35.4 trillion cubic feet (TCF) are gas. An additional 44 billion barrels of undiscovered recoverable oil and oil-equivalent gas resources are expected to be present in the Arctic. Of these total undiscovered resources, it was estimated that 24 billion barrels will occur as oil, and the remainder will consist of 109 TCF of gas and natural gas liquids. Of this gas total, 68 TCF are expected to occur as non-associated gas and 41 TCF should be associated with oil production.

Although there are at least 10 highly prospective areas, the largest resources are estimated to occur in the Beaufort Shelf and the Navarin Basin Shelf. It was also concluded that there is a 1 percent chance that the total quantity of undiscovered recoverable oil and oil-equivalent gas could exceed 99 billion barrels, and a 99 percent chance that it could exceed 13 billion barrels. These undiscovered resources may constitute as much as 40 percent of the total undiscovered recoverable oil and gas resources remaining within U.S. jurisdiction.

Basins appearing to have a low potential should not be ignored. Additional basic geological information could cause significant revisions, either upward or downward, in the estimates. Confirmation of these estimates can be achieved only by extensive leasing and exploratory drilling.

Technology

Large-scale Alaskan North Slope operations and extensive experience in the Cook Inlet, the Canadian Arctic, and the North Sea have demonstrated that, with an economic incentive, the petroleum industry can rapidly develop sufficient technology to safely conduct exploration, design and operate production facilities, and provide transportation in cold, remote, and ice-covered regions, both onshore and offshore. The fundamental techniques of exploration, production, and transportation in Arctic regions are not significantly different than those used elsewhere. The novel problem is the design and operation of systems that can cope with severe sea ice. Continuing research, development, and engineering programs will provide basic information and technology for successful site-specific designs. Technological advances that have the greatest economic potential relate to improving the ability to operate exploration, drilling, production, and transportation systems efficiently during all seasons. This requires coping with low temperatures, poor visibility, storm waves in the Bering Sea, and particularly, the extreme sea ice conditions in the Chukchi and Beaufort Seas.

Exploration technology in the Arctic requires that the usual geological techniques be modified to accommodate weather and specific environmental concerns, but no unique methods are needed or employed. The same is true for geophysical work, although seasonal considerations more generally control the use of heavy geophysical equipment on the tundra and affect the accessibility of offshore areas containing sea ice. The drilling of an exploratory well in the Arctic differs from drilling in other climates in that special techniques have been developed for drilling safely in permafrost areas. Offshore drilling sites must be located in areas free of sea ice or must have a platform or island as a drilling base able to withstand the moving pack ice. Remote locations make logistical support of operations very difficult. These considerations lead to substantially higher costs than those encountered in less hostile regions. Most of the future geological and geophysical technology that will improve exploration will not be Arctic-specific but will be applicable in all areas.

Production technology for Arctic regions requires similar considerations of weather and climate, especially in the design, construction, and installation of production facilities under adverse conditions. Installations and operations must be designed for permafrost, both onshore and in some offshore locations. Offshore structures for drilling, production, storage, and loading that will successfully resist sea ice are a major requirement. It should be

possible to develop safe designs for offshore production islands or platforms within the time period required to lease, explore, and delineate a major oil or gas find.

Additional information on sea ice and its associated problems is being obtained through research programs. These research programs should be continued, as they are needed to complete novel designs and will lead to more cost-efficient operations. Modular construction in temperate climates with transportation of large modules to the site is a proven method of reducing construction costs.

Transportation technology for oil in Arctic regions has been successfully developed for onshore pipelines, as demonstrated by TAPS. Marine transportation has not reached the same level of development. Appropriate tankers and icebreakers can be designed to provide year-round reliable operations to ports south of the Bering Strait handling either crude oil or liquefied natural gas (LNG). Marine vessel operations north of the Bering Strait appear less reliable, and there is a need for more icebreaker experience in this area before tankers are considered an attractive transportation system. Marine pipeline operations in the Arctic should be similar to operations in the North Sea and Cook Inlet, but will be more difficult and demanding because weather and logistics are more severe. As in the case of exploration and production, extended knowledge of the characteristics, conditions, and dynamics of sea ice is needed to optimize and ensure reliability in Arctic marine operations.

Economics

Limited economic evaluations of the Arctic oil and gas resources were made based on assessments of potential resources, costs, and schedules for operations developed in this study. These evaluations demonstrate that large reserves are required to support the high cost of oil and gas field development and associated transportation systems. When transportation systems can be shared by producing areas, significantly improved economics are obtained.

The economic resource base was calculated by combining the reserve evaluations with the resource assessments. Estimates of the capital investment required for exploration, production, and transportation facilities were developed and the sensitivity of the economics to various factors was evaluated.

In evaluation of the oil resources, the economic resource base analysis showed that when applying a 10 percent return as an investment criterion and deleting presently infeasible areas, the total risked mean assessment was reduced from 24 billion barrels to 21 billion barrels. At a 15 percent return it was reduced to 18 billion barrels of economically recoverable oil. The analysis indicates little opportunity for a 20 percent rate of return to be achieved. These results assume that grass roots investments are required for all oil production and transportation and that no incremental use of the TAPS line would be possible at the time of development.

Evaluation of non-associated gas resources showed that when applying a 10 percent return criterion the risked mean assessment of 68 TCF of potentially recoverable non-associated gas is reduced to 10 TCF of economically recoverable gas. In no case was a 15 percent rate of return shown to be achieved. No evaluation was made of the more complex economics of producing associated gas, which could improve the prospects of gas development. Gas transportation from the North Slope was evaluated only on the basis of transporting LNG by tanker from different ports. No case comparable to the proposed Alaska Natural Gas Transportation System (ANGTS) was developed, nor were evaluations of the economics of the incremental use of the ANGTS line developed. Use of this system could substantially increase the economically recoverable gas.

Although considerable variation was shown in the economics for different areas, the uncertainties inherent in estimating all factors in frontier basins, especially the undiscovered resource base, suggest that none of the prospective basins should be excluded from early leasing and exploration.

Impacts

While benefits of oil and gas operations have been demonstrated, it is inevitable that substantial oil and gas development in the

U.S. Arctic regions will have some impact on rural Alaskan populations and on the surrounding environment. The experience of the petroleum industry in recent years demonstrates that such impacts can be managed in a beneficial manner with minimal adverse effects on the environment.

The Arctic area contains about 45,000 inhabitants located in six regional centers and about 60 small villages. This population is distributed over thousands of square miles along the northern and northwestern coasts of Alaska from the Alaskan/Canadian border through the Aleutian Islands. Because oil and gas development is likely to occur only at a few specific points, many of the native villages will not directly experience the impact of development. In the few communities that would be directly affected, expansion will occur in community structure, shoreline resources, local labor markets, and housing. Employment and business opportunities will evolve that could benefit those who choose to participate. In order to maximize these opportunities and minimize any adverse impacts, it is necessary to develop adequate long-term planning and good industry/native relationships.

Environmental impacts can be minimized or avoided in the Arctic by operating practices that have been and continue to be developed by the oil and gas industry in their operations throughout the world, particularly at Prudhoe Bay, the TAPS corridor, the Cook Inlet, the North Sea, and the Canadian Arctic. The Arctic environment is both fragile and biologically important; however, the risk of significant disturbance can be minimized. Accelerated activities in new geographic areas will require an extension of existing technology. However, no problems are perceived that are beyond the projected capability of the industry. As discoveries of oil and gas are made, additional site-specific data will be developed, and research, development, and information gathering will continue. With this information and a continuing commitment to good practices by industry, environmental impacts should be negligible and oil and gas development can proceed safely and successfully in the Arctic.

Regulation

Both the leasing of prospective areas and the permitting of operations in the Arctic are under government control. A multitude of statutes, regulations, and policies have been developed at federal, state, and borough levels, resulting in an elaborate series of regulatory constraints that have increased costs and delayed all aspects of oil and gas development. A major impediment to Arctic development would be removed if these policies and procedures were simplified and expedited.

The aggressive leasing program undertaken by the State of Alaska has made the present Prudhoe Bay development possible. Most of the rest of the area onshore is under federal control and has been closed to development for many years. A limited program to open a portion of the NPRA is under way, but most of the highly prospective North Slope area under federal jurisdiction is still unavailable for exploration activity. The offshore leasing schedule as of July 1981 does not offer some of the most promising areas until 1984 or later. Acceleration and simplification of leasing for these areas would allow oil and gas development to proceed more effectively.

The complicated regulatory system that has been imposed on the industry needs a complete redesign with the permitting and leasing agencies operating under a clear federal policy to expedite Arctic development. Revisions in statutes, regulations, and policies at all levels of government are necessary to accomplish such a simplification. Specific recommendations for such revisions are made in this report.

Appendix F
Acronyms and Abbreviations

ACEC—areas of critical environmental concern

API—American Petroleum Institute

BACT—Best Available Control Technology

BBOE—billion barrels of oil equivalent

BCT—Best Conventional Pollutant Control Technology

BLM—Bureau of Land Management

BPT—Best Practicable Control Technology

CASAC—Clean Air Scientific Advisory Committee of EPA's Science Advisory Board

CO—carbon monoxide

CO_2—carbon dioxide

CZM—Coastal Zone Management

CZMA—Coastal Zone Management Act

DOE—Department of Energy

DWT—deadweight ton

EIS—environmental impact statement

EPA—Environmental Protection Agency

FLPMA—Federal Land Policy and Management Act

GAO—General Accounting Office

GNP—Gross National Product

GRT—gross registered ton

IMCO—Intergovernmental Maritime Consultative Organization

LAER—Lowest Achievable Emission Rate

MARPOL 1973—International Convention for Prevention of Pollution from Ships, 1973

MARPOL 1978—Tanker Safety and Pollution Prevention Convention, 1978

MB/D—thousand barrels per day

MMB/D—million barrels per day

NAAQS—National Ambient Air Quality Standards

NEPA—National Environmental Policy Act

NPDES—National Pollutant Discharge Elimination System

NOAA—National Oceanic and Atmospheric Administration

NO_x—nitrogen oxides

NPC—National Petroleum Council

NPRA—National Petroleum Reserve-Alaska

NPR-4—Naval Petroleum Reserve Number 4

NRC—National Research Council

NSCP—National Spill Contingency Plan

NSPS—New Source Performance Standards

NTL-6—Notice of Lessees and Operator No. 6 Approval of Operations

NWPS—National Wilderness Preservation System

OCS—Outer Continental Shelf

OCSLAA—Outer Continental Shelf Lands Act Amendments of 1978

POTW—publicly owned treatment works

ppm—parts per million

ppmv—parts per million volume

PSD—Prevention of Significant Deterioration

RARE—Roadless Area Review and Evaluation program

RCRA—Resource Conservation and Recovery Act

SIP—State Implementation Plan

SO_2—sulfur dioxide

SO_x—sulfur oxides

SOLAS—International Convention for Safety of Life at Sea

Superfund—Comprehensive Environmental Response, Compensation and Liability Act

TAPS—Trans-Alaska Pipeline System

TCF—trillion cubic feet

TSP—total suspended particulates

UIC—underground injection control

USGS—U.S. Geological Survey

VOC—volatile organic compounds